City of Olivia
Distributed Energy Resource Reporting
2021

Annually the utility shall report to the governing body for its review and approval an annual report including information in subparts 1-3.

Subpart 1. Summary of average retail utility energy rate. A summary of the qualifying facilities that are currently served under average retail utility energy rate.

There are currently no facilities served under the average retail utility energy rate

Subpart 2. Other qualifying facilities. A summary of the qualifying facilities that are not currently served under average retail utility energy rate.

There are currently no facilities served under any rate other than the average retail utility energy rate.

Subpart 3. Wheeling. A summary of the wheeling undertaken with respect to qualifying facilities.

There is currently no wheeling undertaken with respect to qualifying facilities.

City of Olivia
Cogeneration and Small Power Production Tariff
2022

Annually the utility shall file for review and approval, a cogeneration and small power production tariff with the governing body. The tariff must contain schedules 1 – 4.

SCHEDULE 1.

Calculation of the average retail utility energy rates for 2021. "Average retail utility energy rate" means, for any class of utility customer, the quotient of the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales. The computation shall use data from the most recent calendar year available.

Customer Class	Average Retail Utility Energy Rate
Residential	$0.094
Commercial	$0.107
Small Power	$0.107
Large Power	$0.067

SCHEDULE 2.

Schedule 2 shall contain all standard contracts to be used with qualifying facilities, containing applicable terms and conditions.

Attachment 1 – Uniform Contract for Cogeneration and Small Power Production Facilities (See section 14 of Process Manual)

Adopted June 3rd, 2019

Attachment 2 – Minnesota Municipal Interconnection Agreement (MMIA) (See section 15 of Process Manual)

Adopted June 3rd, 2019

Attachment 3 – MMPA Distributed Generation Tariff (See section 16 of Process Manual)

Adopted June 3rd, 2019

SCHEDULE 3.

Schedule 3 shall contain the utility's adopted interconnection process, safety standards, technical requirements for distributed energy resource systems, required operating procedures for interconnected operations, and the functions to be performed by any control and protective apparatus.

City of Olivia
Cogeneration and Small Power Production Tariff
2022

Attachment 4 – City of Olivia Municipal Utilities Distributed Energy Resource Interconnection Process (Resolution 2019-53 Interconnection Process and Rules, Process Overview booklet, Simplified Process booklet, Fast Track Process booklet, and Study Process Booklet, See Resolution 2019-53 and sections 1-4 of Process Manual)

Adopted June 3rd, 2019 – This includes the utility's adopted interconnection process.

Attachment 5 – State of Minnesota Technical Interconnection and Interoperability Requirements (TIIR)

Adopted March 21st, 2022 - This includes the safety standards, technical requirements, required operating procedures, and functions of control and protective apparatus.

SCHEDULE 4.

Schedule 4 shall contain the estimated average incremental energy costs by seasonal, peak and off-peak periods for the utility's power supplier from which energy purchases are first avoided.

Schedule 4 shall also contain the net annual avoided capacity costs, if any, stated per kilowatt-hour and averaged over the on-peak hours and over all hours for the utility's power supplier from which capacity purchases are first avoided.

Both the average incremental energy costs and net annual avoided capacity costs shall be increased by a factor equal to 50 percent of the utility and the utility's power supplier's overall line losses due to distribution, transmission and transformation of electric energy.

Average Incremental Energy Costs

Consumption Category	Rate
7 Day Off-peak	$0.03229
Sat/Sun/Holiday On-peak	$0.04531
Weekday On-peak	$0.05312

*Minnesota Municipal Power Agency (MMPA) is the Power supplier from which energy purchases are first avoided. MMPA does not currently have seasonal rates.

City of Olivia
Cogeneration and Small Power Production Tariff
2022

Net Annual Avoided Capacity Costs

There are currently no avoided capacity costs for 2021 as there are no Distributed Energy Resources connected.

SCHEDULE 5.
MMPA Distributed Generation Payment Rates

	Energy ($/kWh)	Capacity ($/kWh)	REC ($/kWh)
Summer Months (June-Sept)			
On Peak	0.0337	0	0
Off Peak	0.0235	0	0
All Hours	0.0282	0	0
Winter Months (Oct-May)			
On Peak	0.0309	0	0
Off Peak	0.0232	0	0
All Hours	0.0268	0	0
Annual (January-December)	0.0273	0	0

UNIFORM CONTRACT FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES

THIS CONTRACT is entered into ___________________, ___, by _______________ _____________________, a municipal utility under Minnesota law, (hereafter called "Utility") and ____ (hereafter called "QF").

RECITALS

The QF has installed electric generating facilities, consisting of ___________________ ____________________________ (Description of facilities), rated at ____kilowatts AC of electricity, on property located at ____ ____.

The QF is a customer of the Utility located within the assigned electric service territory of the Utility.

The QF is prepared to generate electricity in parallel with the Utility.

The QF's electric generating facilities meet the requirements of the rules adopted by the Utility on Cogeneration and Small Power Production and any technical standards for interconnection the Utility has established that are authorized by those rules.

The Utility is obligated under federal and Minnesota law to interconnect with the QF and to purchase electricity offered for sale by the QF.

A contract between the QF and the Utility is required.

AGREEMENTS

The QF and the Utility agree:

1. The Utility will sell electricity to the QF under the rate schedule in force for the class of customer to which the QF belongs.

2. The Utility will buy electricity from the QF under the current rate schedule filed with the city council or city-appointed governing body of the utility. The QF elects the rate schedule category hereinafter indicated:

____ a. Average retail utility energy rate.

- QF capacity must be less than 40 kW.

____ b. Simultaneous purchase and sale billing rate.

- QF capacity must be less than 40 kW.

____ c. Roll-over credits.

- QF capacity must be less than 40 kW.

____ d. Time-of-day purchase rates.

- QF capacity must be 40 kW or more and less than or equal to 100 kW.

A copy of the presently approved rate schedule is attached to this contract.

3. The rates for sales and purchases of electricity may change over the time this contract is in force, due to actions of the Utility or the State of Minnesota, and the QF and the Utility agree that sales and purchases will be made under the rates in effect each month during the time this contract is in force.

4. The Utility will compute the charges and payments for purchases and sales for each billing period. Any net credit to the QF, other than kilowatt-hour credits under clause 2(c), will be made under one of the following options as chosen by the QF.

____ a. Credit to the QF's account with the Utility.
____ b. Paid by check or electronic payment service to the QF within fifteen (15) days of the billing date.

5. Renewable energy credits associated with generation from the facility are owned by:
____.

6. The QF must operate its electric generating facilities within any rules, regulations, and policies adopted by the Utility not prohibited by the rules governing Cogeneration and Small Power Production on the Utility's system which provide reasonable technical connection and operating specifications for the QF and are consistent with the Minnesota Public Utilities Commission's rules on Cogeneration and Small Power Production, as required under Minnesota Statutes §216B.164, subdivision 9.

7. The QF will not enter into an arrangement whereby electricity from the generating facilities will be sold to an end user in violation of the Utility's exclusive right to provide electric service in its service area under Minnesota Statutes, §216B.37-44.

8. The QF will operate its electric generating facilities so that they conform to the national, state, and local electric and safety codes, and will be responsible for the costs of conformance.

9. The QF is responsible for the actual, reasonable costs of interconnection which are estimated to be $___________. The QF will pay the Utility in this way:

____

____.

10. The QF will give the Utility reasonable access to its property and electric generating facilities if the configuration of those facilities does not permit disconnection or testing from the Utility 's side of the interconnection. If the Utility enters the QF's property, the Utility will remain responsible for its personnel.

11. The Utility may stop providing electricity to the QF during a system emergency. The Utility will not discriminate against the QF when it stops providing electricity or when it resumes providing electricity.

12. The Utility may stop purchasing electricity from the QF when necessary for the Utility to construct, install, maintain, repair, replace, remove, investigate, or inspect any equipment or facilities within its electric system. The Utility may stop purchasing electricity from the QF in the event the generating facilities listed in this contract are documented to be causing power quality, safety or reliability issues to the Utility's electric distribution system.

The Utility will notify the QF before it stops purchasing electricity in this way:

____

____.

13. The QF will keep in force general liability insurance against personal or property damage due to the installation, interconnection, and operation of its electric generating facilities. The amount of insurance coverage will be $ ____________. (The amount must be consistent with the distributed generation tariff adopted by the Utility pursuant to Minnesota Statutes §216B.1611, subdivision 3, clause 2.)

14. The QF and the Utility agree to attempt to resolve all disputes arising hereunder promptly and in a good faith manner.

15. The city council or city-appointed body governing the Utility has authority to consider and determine disputes, if any, that arise under this contract in accordance with procedures in the rules it adopts implementing Minnesota Statute §216B.164, pursuant to §216B.164, subdivision 9.

16. This contract becomes effective as soon as it is signed by the QF and the Utility. This contract will remain in force until either the QF or the Utility gives written notice to the other that the contract is canceled. This contract will be canceled thirty (30) days after notice is given. If the listed electric generating facilities are not interconnected to the Utility's distribution system within twelve months of the contract being signed by the QF and the Utility, the contract terminates. The QF and the Utility may delay termination by mutual agreement.

17. Neither the QF nor the Utility will be considered in default as to any obligation if the QF or the Utility is prevented from fulfilling the obligation due to an act of God, labor disturbance, act of public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, an order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or other cause beyond the QF's or Utility's control. However, the QF or Utility whose performance under this contract is hindered by such an event shall make all reasonable efforts to perform its obligations.

18. This contract can only be amended or modified by mutual agreement in writing signed by the QF and the Utility.

19. The QF must notify the Utility prior to any change in the electric generating facilities' capacity size or generating technology according to the interconnection process adopted by the Utility.

20. Termination of this contract is allowed (i) by the QF at any time without restriction; (ii) by Mutual Agreement between the Utility and the QF; (iii) upon abandonment or removal of electric generating facilities by the QF; (iv) by the Utility if the electric generating facilities are continuously non-operational for any twelve (12) consecutive month period; (v) by the Utility if the QF fails to comply with applicable interconnection design requirements or fails to remedy a violation of the interconnection process; or (vi) by the Utility upon breach of this contract by the QF unless cured with notice of cure received by the Utility prior to termination.

21. In the event this contract is terminated, the Utility shall have the rights to disconnect its facilities or direct the QF to disconnect its generating facilities.

22. This contract shall continue in effect after termination to the extent necessary to allow either the Utility or the QF to fulfill rights or obligations that arose under the contract.

23. Transfer of ownership of the generating facilities shall require the new owners and the Utility to execute a new contract. Upon the execution of a new contract with the new owners this contract shall be terminated.

24. The QF and the Utility shall at all times indemnify, defend, and save each other harmless from any and all damages, losses, claims, including claims and actions relating to injury or death of any person or damage to property, costs and expenses, reasonable attorneys' fees and court costs, arising out of or resulting from the QF's or the Utility's performance of its obligations under this contract, except to the extent that such damages, losses or claims were caused by the negligence or intentional acts of the QF or the Utility.

25. The Utility and the QF will each be responsible for its own acts or omissions and the results thereof to the extent authorized by law and shall not be responsible for the acts or omissions of any others and the results thereof.

26. The QF's and the Utility's liability to each other for failure to perform its obligations under this contract shall be limited to the amount of direct damage actually occurred. In no event, shall the QF or the Utility be liable to each other for any punitive, incidental, indirect, special, or consequential damages of any kind whatsoever, including for loss of business opportunity or profits, regardless of whether such damages were foreseen.

27. The Utility does not give any warranty, expressed or implied, to the adequacy, safety, or other characteristics of the QF's interconnected system.

28. This contract contains all the agreements made between the QF and the Utility. The QF and Utility are not responsible other than those stated in this contract.

THE QF AND THE UTILITY HAVE READ THIS CONTRACT AND AGREE TO BE BOUND BY ITS TERMS. AS EVIDENCE OF THEIR AGREEMENT, THEY HAVE EACH SIGNED THIS CONTRACT BELOW ON THE DATE LISTED BY SIGNER.

QF

By: ________________________________

Printed Name:_______________________

DATE: _____________________________

UTILITY

By: ________________________________

Printed Name:_______________________

DATE: _____________________________

Contract Version: *May 2019*

Minnesota Municipal Power Agency's 7 MW Buffalo Solar Buffalo, MN

MMIA INTERCONNECTION AGREEMENT

ABSTRACT

For use in lieu of the Utility's Uniform Contract

Contents

i. Contact Information

Contact information for each Party is listed below along with the basic information describing the Distributed Energy Resource (DER) system.

Area EPS Operator Information

Area EPS Operator: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

DER System Information

Application Number: ______________________________

Type of DER System: ______________________________

Capacity Rating of System (AC): ______________________________

Limited Capacity Rating (AC): ______________________________

Address of DER System: ______________________________

____

THIS AGREEMENT is made and entered into this _____day of______________ 20___ by and between____, ("Interconnection Customer"), and The City of Olivia Municipal Utilities, a municipal utility existing under the laws of the State of Minnesota, ("Area EPS Operator"). Interconnection Customer and Area EPS Operator each may be referred to as a "Party," or collectively as the "Parties."

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

1 Scope and Limitations of Agreement

1.1. This Agreement is intended to provide for the Interconnection Customer to interconnect at the Point of Common Coupling and operate a Distributed Energy Resource with a Nameplate Rating of 10 Megawatts (MW) or less in parallel with the Area EPS at the location identified above and in the Interconnection Application.

1.2. This Agreement shall be used for Interconnection Applications submitted under the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process except for those Interconnection Applications that qualify and choose for the Uniform Contract, to replace the need for this Agreement.

1.3. This Agreement governs the terms and conditions under which the Interconnection Customer's Distributed Energy Resource will interconnect with, and operate in parallel with, the Area EPS Operator's Distribution System.

1.4. Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1, the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process, or the body of this Agreement.

1.5. This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Area EPS Operator.

1.6. Nothing in this Agreement is intended to affect any other agreement between the Area EPS Operator and the Interconnection Customer.

2 Responsibilities of the Parties

2.1. The Parties shall perform all obligations of this Agreement in accordance with the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process, Minnesota Technical Requirements, all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

2.2. The Interconnection Customer shall construct, interconnect, operate and maintain its Distributed Energy Resource and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule and, in accordance with this Agreement, and with Good Utility Practice.

2.3. The Area EPS Operator shall construct, operate, and maintain its Distribution System and its Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

2.4. The Interconnection Customer agrees to construct its facilities or systems in accordance with the Minnesota Technical Requirements and this Agreement; including, applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, Institute of Electrical and Electronics Engineers (IEEE), Underwriter's Laboratory (UL), and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Distributed Energy Resource so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Area EPS Operator and any Affected Systems.

2.5. Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now owns or subsequently owns unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of common coupling. The Area EPS Operator and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Area EPS Operator's Distribution System, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

2.6. The Area EPS Operator shall coordinate with all Affected Systems to support the interconnection.

3 Parallel Operation Obligations

3.1. Once the Distributed Energy Resource has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Distributed Energy Resource in the applicable control area, including, but not limited to; 1) the rules and procedures concerning the operation of generation set forth by the applicable system operator(s) for the Area EPS Operator's Distribution System provided or referenced in an attachment to this Agreement and; 2) the Operating Requirements set forth in Attachment 5 of this Agreement. The Minnesota Technical Requirements for interconnection are covered in a separate document, a copy of which has been made available to the Interconnection Customer and incorporated and made part of this Agreement by this reference.

4 Metering

4.1. As described in City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Overview Process Section 9.1, the Interconnection Customer shall be responsible for the Area EPS Operator's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

5 Distributed Energy Resource Capabilities and Grid Reliability

5.1. The Minnesota Technical Requirements outlines the Parties responsibilities consistent with IEEE 1547 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces which provides requirements relevant to the interconnection and interoperability performance, operation and testing, and, to safety, maintenance and security considerations.

5.2. The Area EPS Operator may offer the Interconnection Customer the option to utilize required DER capabilities to mitigate Interconnection Customer costs related to Upgrades or Interconnection Facilities to address anticipated system impacts from the engineering review (i.e. Initial Review, Supplemental Review, or Study Process described in the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process.)

6 Equipment Testing and Inspection

6.1. As described in the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Overview Process Section 9.3, the Interconnection Customer shall test and inspect its Distributed Energy Resource and Interconnection Facilities prior to interconnection pursuant to Minnesota Technical Requirements and this Agreement.

7 Authorization Required Prior to Parallel Operation

7.1. As described in the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Overview Process Section 9.5, the Area EPS Operator shall use Reasonable Efforts to list applicable parallel operation requirements by attaching the Minnesota Technical Requirements and/or including them in Attachment 5 to this Agreement. Additionally, the Area EPS Operator shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. Pursuant to the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Overview Process Section 8.5, the Interconnection Customer shall not operate its Distributed Energy Resource in parallel with the Area EPS Operator's Distribution System without prior written authorization of the Area EPS Operator.

8 Right of Access

8.1. Upon reasonable notice, the Area EPS Operator may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Distributed Energy Resource first produces energy to inspect the interconnection, and observe the commissioning of the Distributed Energy Resource (including any required testing), startup, and operation for a period of up to three (3) Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Area EPS Operator at least five (5) Business Days prior to conducting any on-site verification testing of the Distributed Energy Resource.

8.2. Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Area EPS Operator shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

8.3. Each Party shall be responsible for its costs associated with the interconnection of the DER system as outlined in the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Overview Process Section 9.3 and the Minnesota Technical Requirements.

9 Effective Date

9.1 This Agreement shall become effective upon execution by the Parties.

10 Term of Agreement

10.1. This Agreement shall become effective on the Effective Date and shall remain in effect from the Effective Date unless terminated earlier in accordance with Section 11 of this Agreement.

11 Termination

11.1. No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination.

11.2. The Interconnection Customer may terminate this Agreement at any time by giving the Area EPS Operator twenty (20) Business Days written notice.

11.3. The Area EPS Operator may terminate this Agreement if the listed electric generating facilities are not interconnected to the Area EPS Operator's distribution system within thirty-six (36) months of this Agreement signed by the Parties. The Parties may choose to delay termination by mutual agreement.

11.4. Either Party may terminate this Agreement after Default pursuant to Section 3.

11.5. Upon termination of this Agreement, the Distributed Energy Resource will be disconnected from the Area EPS Operator's Distribution System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this Agreement or such non-terminating Party otherwise is responsible for these costs under this Agreement.

11.6. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

11.7. The provisions of this article shall survive termination or expiration of this Agreement.

12 Temporary Disconnection

12.1. Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

12.2. Emergency Conditions. Under emergency conditions, the Area EPS Operator may immediately suspend interconnection service and temporarily disconnect the Distributed Energy Resource. The Area EPS Operator shall use Reasonable Efforts to notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Distributed Energy Resource. The Interconnection Customer shall use Reasonable Efforts to notify the Area EPS Operator promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Area EPS Operator's Distribution System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

12.3. Temporary Interruption. The Area EPS Operator may interrupt interconnection service or curtail the output of the Distributed Energy Resource and temporarily disconnect the Distributed Energy Resource from the Area EPS Operator's Distribution System when necessary for routine maintenance, construction, or repairs on the Area EPS Operator's Distribution System. The Area EPS Operator shall use Reasonable Efforts to provide the Interconnection Customer with three (3) Business Days' notice prior to such interruption. The Area EPS Operator shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

12.4. Forced Outage. During any forced outage, the Area EPS Operator may suspend interconnection service to effect immediate repairs on the Area EPS Operator's Distribution System. The Area EPS Operator shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Area EPS Operator shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

12.5. Adverse Operating Effects. The Area EPS Operator shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Distributed Energy Resource may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Distributed

Energy Resource could cause damage to the Area EPS Operator's Distribution System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Area EPS Operator may disconnect the Distributed Energy Resource. The Area EPS Operator shall provide the Interconnection Customer with five Business Day notice of such disconnection, unless the provisions of Section 12.2 apply.

12.6. Modification of the Distributed Energy Resource. The Interconnection Customer must receive written authorization from the Area EPS Operator before making any change to the Distributed Energy Resource that may have a material impact on the safety or reliability of the Distribution System. Such authorization shall not be unreasonably withheld if the modification is not a Material Modification. Material Modifications, including an increase Nameplate Rating or capacity, may require the Interconnection Customer to submit a new Interconnection Application as described in the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Overview Process Section 7. If the Interconnection Customer makes such modification without the Area EPS Operator's prior written authorization, the latter shall have the right to temporarily disconnect the Distributed Energy Resource.

12.7. Reconnection. The Parties shall cooperate with each other to restore the Distributed Energy Resource, Interconnection Facilities, and the Area EPS Operator's Distribution System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

12.8. Treatment Similar to Other Retail Customers. If the Interconnection Customer receives retail electrical service at the same site as the Distributed Energy Resource, it may also be disconnected consistent with the rules and practices for disconnecting other retail electrical customers.

12.9. Disconnection for Default. If the Interconnection Customer is in Default of this Agreement, it may be disconnected after a sixty (60) day written notice is provided and the Default is not cured during this sixty (60) day notice. This provision does not apply to disconnection based on Sections 12.2, 12.3, 12.4 or 12.5 of this Agreement.

13 Cost Responsibility for Interconnection Facilities and Distribution Upgrades

13.1 Interconnection Facilities. The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Area EPS

Operator shall provide a good faith estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Area EPS Operator.

13.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Area EPS Operator's Interconnection Facilities.

13.3 Distribution Upgrades. The Area EPS Operator shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. The Area EPS Operator shall provide a good faith estimate cost, including overheads, for the purchase and construction of the Distribution Upgrades and provide a detailed itemization of such costs. If the Area EPS Operator and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

14 Cost Responsibility for Network Upgrades

14.1. Applicability. No portion of Section 14 shall apply unless the interconnection of the Distributed Energy Resource requires Network Upgrades.

14.2. Network Upgrades. The Area EPS Operator or the Transmission Owner shall design, procure, construct, install, and own the Network Upgrades described in Attachment 6 of this Agreement. The Area EPS Operator shall provide a good faith estimate cost, including overheads, for the purchase and construction of the Network Upgrades and provide a detailed itemization of such costs. If the Area EPS Operator and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Area EPS Operator elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, shall be borne initially by the Interconnection Customer.

14.3. Repayment of Amounts Advanced for Network Upgrades. The Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to the Area EPS Operator and Affected System operator, if any, for Network Upgrades, including any tax gross-up or other tax-related payments associated with the Network Upgrades, and not otherwise refunded to the Interconnection Customer, to be paid to the Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under the Area EPS Operator's Tariff and Affected System's Tariff for transmission services with respect to the Distributed Energy Resource. Any repayment shall include interest calculated in accordance with the methodology set forth in Federal Energy Regulatory Commission's (FERC's) regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. The Interconnection Customer may assign such repayment rights to any person.

14.4. Notwithstanding the foregoing, the Interconnection Customer, the Area EPS Operator, and any applicable Affected System operators may adopt any alternative payment schedule that is mutually agreeable so long as the Area EPS Operator and said Affected System operators take one of the following actions no later than five years from the Commercial Operation Date: (1) return to the Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that the Area EPS Operator or any applicable Affected System operators will continue to provide payments to the Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond 20 years from the commercial operation date.

14.5. If the Distributed Energy Resource fails to achieve commercial operation, but it or another Distributed Energy Resource is later constructed and requires use of the Network Upgrades, the Area EPS Operator and Affected System operator shall at that time reimburse the Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Distributed Energy Resource, if different, is responsible for identifying the entity to which reimbursement must be made.

14.6. <u>Special Provisions for Affected Systems.</u> Unless the Area EPS Operator provides, under this Agreement, for the repayment of amounts advanced to any applicable Affected System operators for Network Upgrades, the Interconnection Customer and Affected System operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by the Interconnection Customer to Affected System operator as well as the repayment by Affected System Operator.

14.7. Rights Under Other Agreements. Notwithstanding any other provision of this Agreement, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Distributed Energy Resource.

15 Billing, Payment, Milestones, and Financial Security

15.1. Billing and Payment Procedures and Final Accounting. The Area EPS Operator shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement, and the Interconnection Customer shall pay each bill, pursuant to the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process documents, or as otherwise agreed to by the Parties.

15.2. Within 80 Business Days (approximately 4 calendar months) of completing the construction and installation of the Area EPS Operator's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Area EPS Operator shall provide the Interconnection Customer with a final accounting report, as described in the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Fast Track Process Section 9.4.3 and the Study Process Section 11.4.3.

15.3. Milestones. Pursuant to the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Fast Track Process Section 9.1 and the Study Process Section 11.1, the Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement.

15.4. Financial Security Arrangements. Pursuant to the City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Fast Track Process Section 9.5 and the Study Process Section 11.5, the Interconnection Customer shall provide the Area EPS Operator, at the Interconnection Customer's option, a guarantee, letter of credit or other form of security that is reasonably acceptable to the Area EPS Operator and is consistent with the Minnesota Uniform Commercial Code. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Area EPS Operator's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Area EPS Operator under this Agreement during its term. In addition:

15.4.1. The guarantee must be made by an entity that meets the creditworthiness requirements of the Area EPS Operator, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

15.4.2. The letter of credit must be issued by a financial institution or insurer reasonably acceptable to the Area EPS Operator and must specify a reasonable expiration not sooner than sixty (60) Business Days (three calendar months) after the due date for the issuance of the final bill.

16 Assignment, Force Majeure, Consequential Damages, and Default

16.1. This Agreement may be assigned by either Party upon 15 Business Days prior written notice and opportunity to object by the other Party; provided that:

16.1.1. Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the Area EPS Operator of any such assignment.

16.1.2. Interconnection Customer shall have the right to assign this Agreement, without the consent of the Area EPS Operator, for collateral security purposes to aid in providing financing for the Distributed Energy Resource, provided that the Interconnection Customer will promptly notify the Area EPS Operator of any such assignment.

16.1.3. Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

17 Limitations of Liability

17.1. Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

18 Non-Warranty

18.1. The Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Interconnection Customer, including without limitation the Distributed Energy Resource and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator.

19 Indemnity

19.1. This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Section 17.

19.2. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

19.3. If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

19.4. If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

19.5. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

19.6. This indemnification obligation shall apply notwithstanding any negligent or intentional acts, errors or omissions of the Indemnified Party, but the Indemnifying Party's liability to indemnify the Indemnifying Party shall be reduced in proportion to the percentage by which the Indemnified Party's negligent or intentional acts, errors or omissions caused damaged.

19.7. Neither Party shall be indemnified for its damages resulting from its sole negligence, intentional acts or willful misconduct. These indemnity provisions shall not be construed to relieve any insurer of its obligation to pay claims consistent with the provisions of a valid insurance policy.

20 Consequential Damages

20.1. Other than as expressly provided for in this Agreement, neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

21 Force Majeure

21.1. If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

22 Default

22.1. No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in Section 21, the defaulting Party shall have sixty (60) calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within sixty (60) calendar days, the defaulting Party shall commence such cure within twenty (20) calendar days after notice and continuously and diligently complete such cure within six (6) months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

22.2. If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

23 Insurance

23.1. An Area EPS Operator may only require an Interconnection Customer to purchase insurance covering damages pursuant to the applicable City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process document in which the distributed energy resource falls under.

23.2. The Area EPS Operator agrees to maintain general liability insurance or self-insurance consistent with the Area EPS Operator's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Area EPS Operator's liabilities undertaken pursuant to this Agreement.

23.3. The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

23.4. Failure of the Interconnection Customer or Area EPS Operator to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

24 Confidentiality

24.1. Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such. If requested by either Party, the other Party shall provide in writing the basis for asserting that the information warrants confidential treatment. Parties providing a Governmental Authority trade secret, privileged or otherwise not public data under Minnesota Government Data Privacy Act, Minnesota Statutes Chapter 13, must provide information consistent with the Commission's September 1, 1999 Revised Procedures for Handling Trade Secret and Privileged Data.

24.2. Confidential Information does not include information previously in the public domain with proper authorization, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be publicly divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements that could not otherwise be fulfilled by not making the information public.

24.3. Each Party shall hold in confidence and shall not disclose Confidential Information, to any person (except employees, officers, representatives and agents, who agree to be bound by this section). Confidential Information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency or entity with the right, power, and authority to do so, requests or requires either Party, by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver the Party shall disclose such confidential information which, in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded any confidential information so furnished.

24.4. Critical infrastructure information or information that is deemed or otherwise designated by a Party as Critical Energy/Electric Infrastructure Information (CEII) pursuant to FERC regulation 18 C.F.R. §388.133, as may be amended from time to time, may be subject to further protections for disclosure as required by FERC or FERC regulations or orders and the disclosing Party's CEII policies.

24.5. Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

24.6. Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

25 Disputes

The Parties agree in a good faith effort to attempt to resolve all disputes arising out of the interconnection process and associated study and Interconnection Agreements. The Parties agree to follow the established dispute resolution policy adopted by the Area EPS Operator.

26 Taxes

26.1. The Parties agree to follow all applicable tax laws and regulations, consistent with Internal Revenue Service and any other relevant local, state and federal requirements.

26.2. Each Party shall cooperate with the other to maintain the other Party's tax status. It is incumbent on the Party seeking to maintain its tax status to provide formal written notice to the other Party detailing what exact cooperation it is seeking from the other Party well prior to any deadlines by which any such action would need to be taken. Nothing in this Agreement is intended to adversely affect, if applicable, the Area EPS Operator's tax-exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

27 Miscellaneous

27.1. Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the Olivia City Council and the laws of the state of Minnesota, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

27.2. Amendment. The Parties may amend this Agreement by a written instrument duly executed by both Parties, or under Section 27.12 of this Agreement.

27.3. No Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

27.4. Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party. Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Area EPS Operator. Any waiver of this Agreement shall, if requested, be provided in writing.

27.5. Entire Agreement. This Agreement, including all Attachments, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement. This Agreement can only be amended or modified in writing signed by both Parties.

27.6. Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument. Electronic signatures are acceptable if the Area EPS Operator has made such a determination pursuant to City of Olivia Municipal Utilities Distributed Energy Resources Interconnection Process Overview Process Section 4.1.

27.7. No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

27.8. Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

27.9. Security Arrangements. Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All public utilities are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

27.10. Environmental Releases. Each Party shall notify the other Party, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Distributed Energy Resource or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any governmental authorities addressing such events.

27.11. Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement. Each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

27.11.1. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made. In no event shall the Area EPS Operator be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

27.11.2. The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

27.12. Inclusion of Area EPS Operator Tariff and Rules. The interconnection services provided under this Agreement shall at all times be subject to the terms and conditions set forth in the rate schedules and rules applicable to the electric service provided by the Area EPS Operator, which rate schedules and rules are hereby incorporated into this Agreement by this reference.

28 Notices

28.1. General. Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified as follows:

Area EPS Operator Information

Area EPS Operator: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

28.2. Billing and Payment. Billing and payments shall be sent to the addresses set out below:

Area EPS Operator Information

Area EPS Operator: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

28.3. Alternative Forms of Notice. Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephone or e mail to the telephone numbers and e-mail addresses set out below:

Area EPS Operator Information

Area EPS Operator: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

28.4. Designated Operating Representative. The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Area EPS Operator Information

Area EPS Operator: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

28.5. Changes to Notification. Either Party may change this information by giving five Business Days written notice to the other Party prior to the effective date of the change.

31 Signatures

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

City of Olivia	Interconnection Customer
Signed: _____________________________	Signed: _____________________________
Name (Printed):	Name (Printed):
____________________________________	___________________________________
Title: _______________________________	Title: _______________________________

Attachment I: Glossary of Terms

Affected System – Another Area EPS Operator's System, Transmission Owner's Transmission System, or Transmission System connected generation which may be affected by the proposed interconnection.

Applicant Agent – A person designated in writing by the Interconnection Customer to represent or provide information to the Area EPS on the Interconnection Customer's behalf throughout the interconnection process.

Area EPS – The electric power distribution system connected at the Point of Common Coupling.

Area EPS Operator – An entity that owns, controls, or operates the electric power distribution systems that are used for the provision of electric service in Minnesota. For this Interconnection Process the Area EPS Operator is The City of Olivia Municipal Utilities

Business Day – Monday through Friday, excluding Holidays as defined by Minn. Stat. §645.44, Subdivision 5. Any communication to have been sent or received after 4:30 p.m. Central Prevailing Time or on a Saturday, Sunday or holiday shall be considered to have been sent on the next Business Day.

Certified Equipment – Certified equipment is equipment that has been tested by a national recognized lab meeting a specific standard. For DER systems, UL 1741 listing is a common form of DER inverter certification. Additional information is seen in the Certification Codes and Standards document.

Confidential Information – Any confidential and/or proprietary information provided by one Party to the other Party and is clearly marked or otherwise designated "Confidential." All procedures, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information. See Overview Process Section 12.1 for further information.

Distributed Energy Resource (DER) – A source of electric power that is not directly connected to a bulk power system or central station service. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER. For the purpose of the Interconnection Process and interconnection agreements, the DER includes the Customer's Interconnection Facilities but shall not include the Area EPS Operator's Interconnection Facilities.

Distribution System – The Area EPS facilities which are not part of the Local EPS, Transmission System or any generation system.

Distribution Upgrades – The additions, modifications, and upgrades to the Distribution System at or beyond the Point of Common Coupling to facilitate interconnection of the DER and render the distribution service necessary to affect the Interconnection Customer's connection to the Distribution System. Distribution Upgrades do not include Interconnection Facilities.

Electric Power System (EPS) – The facilities that deliver electric power to a load.

Fast Track Process – The procedure as described in the Interconnection Process - Fast Track Process for evaluating an Interconnection Application for a DER that meets the eligibility requirements in the Overview Process Section 2.3.

Force Majeure Event – An act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, an order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or another cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Area EPS Operator, or any Affiliate thereof. The utility's local governing body is the authority governing interconnection requirements unless otherwise provided for in the Minnesota Technical Requirements.

Interconnection Agreement – The terms and conditions between the Area EPS Operator and Interconnection Customer (Parties). See Section 8 in the Overview Process**Error! Reference source not found.** for when the Uniform Contract or Interconnection Agreement applies.

Interconnection Application – The Interconnection Customer's request to interconnect a new or modified, as described in Section 4 of the Overview Process, DER. See Simplified Application Form and Interconnection Application Form.

Interconnection Customer – The person or entity, including the Area EPS Operator, whom will be the owner of the DER that proposes to interconnect a DER(s) with the Area EPS Operator's Distribution System. The Interconnection Customer is responsible for ensuring the DER(s) is designed, operated and maintained in compliance with the Minnesota Technical Requirements.

Interconnection Facilities – The Area EPS Operator's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the DER and the Point of Common Coupling, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the DER to the Area EPS Operator's System. Some examples of Customer Interconnection Facilities include: supplemental DER devices, inverters, and associated wiring and cables up to the Point of DER Connection. Some examples of Area EPS Operator Interconnection Facilities include sole use facilities; such as, line extensions, controls, relays, switches, breakers, transformers and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Process – The Area EPS Operator's interconnection standards in this document.

Material Modification – A modification to machine data, equipment configuration or to the interconnection site of the DER at any time after receiving notification by the Area EPS Operator of a complete Interconnection Application that has a material impact on the cost, timing, or design of any Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later Queue Position or the safety or reliability of the Area EPS.[1]

MN Technical Requirements – The term including all of the DER technical interconnection requirement documents for the state of Minnesota; including Attachment 2 Distributed Generation Interconnection Requirements established in the Commission's September 28, 2004 Order in E-999/CI-01-1023) until superseded and upon Commission approval of updated

[1] A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) changes the physical location of the point of common coupling; such that it is likely to have an impact on technical review; (2) increases the nameplate rating or output characteristics of the Distributed Energy Resource; (3) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (4) changes transformer connection(s) or grounding; and/or (5) changes to a certified inverter with different specifications or different inverter control settings or configuration. A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes the ownership of a Distributed Energy Resource; (2) changes the address of the Distributed Energy Resource, so long as the physical point of common coupling remains the same; (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; and/or (4) increases the DC/AC ratio but does not increase the maximum AC output capability of the Distributed Energy Resource in a way that is likely to have an impact on technical review.

Minnesota DER Technical Interconnection and Interoperability Requirements in E-999/CI-16-521 (anticipated July 2019.)

Nameplate Rating - nominal voltage (V), current (A), maximum active power (kWac), apparent power (kVA), and reactive power (kVar) at which a DER is capable of sustained operation. For a Local EPS with multiple DER units, the aggregate nameplate rating is equal to the sum of all DERs nameplate rating in the Local EPS. For purposes of the Attachment V in the Interconnection Agreement, the DER system's capacity may, with the Area EPS's agreement, be limited thought use of control systems, power relays or similar device settings or adjustments as identified in IEEE 1547. The nameplate ratings referenced in the Interconnection Process are alternating current nameplate DER ratings at the Point of DER Coupling.

Network Upgrades – Additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the DER interconnects with the Area EPS Operator's System to accommodate the interconnection with the DER to the Area EPS Operator's System. Network Upgrades do not include Distribution Upgrades.

Operating Requirements – Any operating and technical requirements that may be applicable due to the Transmission Provider's technical requirements or Minnesota Technical Requirements, including those set forth in the Interconnection Agreement.

Party or Parties – The Area EPS Operator and the Interconnection Customer.

Point of Common Coupling (PCC)– The point where the Interconnection Facilities connect with the Area EPS Operator's Distribution System. See figure 1. Equivalent, in most cases, to "service point" as specified by the Area EPS Operator and described in the National Electrical Code and the National Electrical Safety Code.

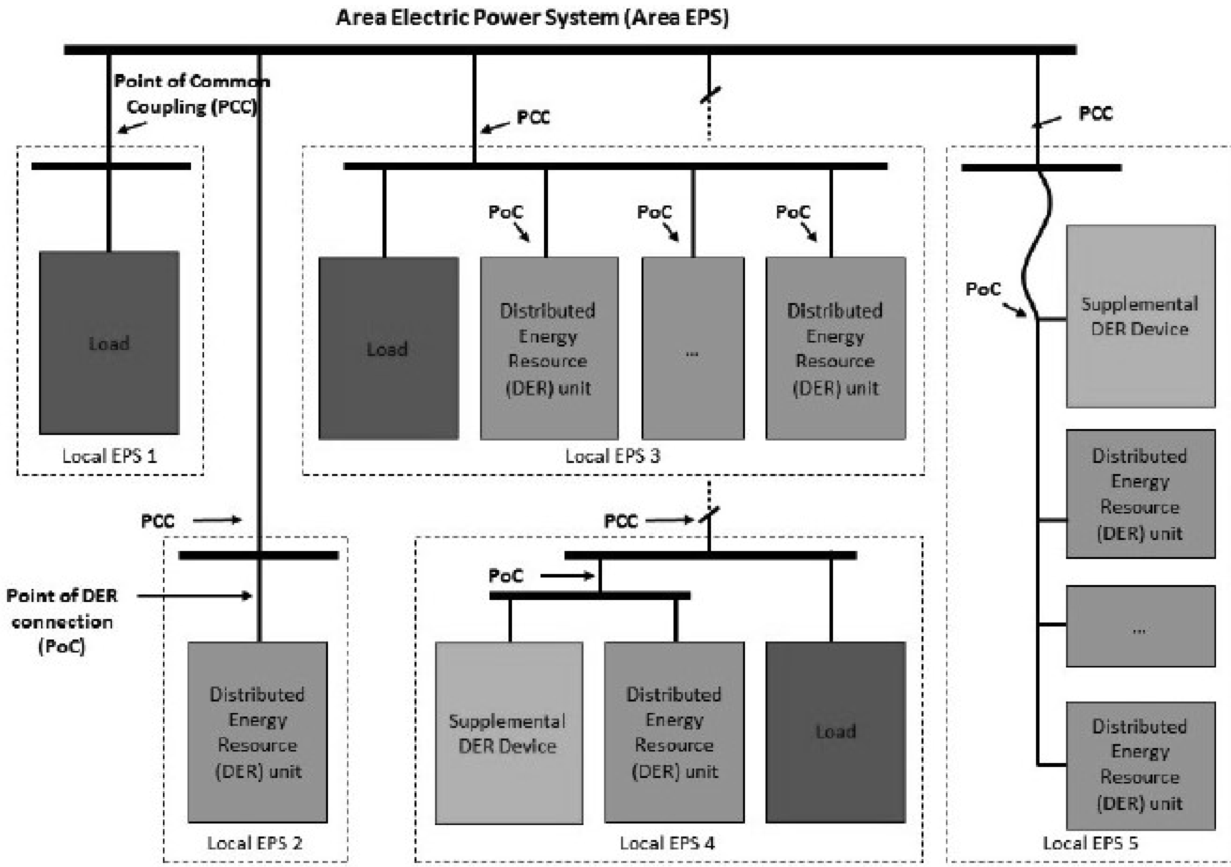

Figure 1: Point of Common Coupling and Point of DER Connection

(Source: IEEE 1547)

Point of DER Connection (PoC) – When identified as the Reference Point of Applicability, the point where an individual DER is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS (e.g. terminals of the inverter when no supplemental DER device is required.) For DER unit(s) that are not self-sufficient to meet the requirements without a supplemental DER device(s), the Point of DER Connection is the point where the requirements of this standard are met by DER in conjunction with a supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

Queue Position – The order of a valid Interconnection Application, relative to all other pending valid Interconnection Applications, that is established based upon the date- and time- of receipt of the complete Interconnection Application as described in Section 4.7 of the Overview Process**Error! Reference source not found.**.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under these procedures, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Reference Point of Applicability – The location, either the Point of Common Coupling or the Point of DER Connection, where the interconnection and interoperability performance requirements specified in IEEE 1547 apply. With mutual agreement, the Area EPS Operator and Customer may determine a point between the Point of Common Coupling and Point of DER Connection. See Minnesota Technical Requirements for more information.

Simplified Process – The procedure for evaluating an Interconnection Application for a certified inverter-based DER no larger than 20 kW that uses the screens described in the Interconnection Process – Simplified Process document. The Simplified Process includes simplified procedures.

Study Process – The procedure for evaluating an Interconnection Application that includes the scoping meeting, system impact study, and facilities study.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System relevant to the Interconnection.

Transmission Provider – The entity (or its designated agent) that owns, leases, controls, or operates transmission facilities used for the transmission of electricity. The term Transmission Provider includes the Transmission Owner when the Transmission Owner is separate from the Transmission Provider. The Transmission Provider may include the Independent System Operator or Regional Transmission Operator.

Transmission System – The facilities owned, leased, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service. See the Commission's July 26, 2000 Order Adopting Boundary Guidelines for Distinguishing Transmission from Generation and Distribution Assets in Docket No. E-999/CI-99-1261.

Uniform Contract – the Area EPS Operator's Agreement for Cogeneration and Small Power Production Facilities (Uniform Contract) that may be applied to all qualifying new and existing interconnections between the Area EPS Operator and a DER system having capacity less than 40 kilowatts.

Upgrades – The required additions and modifications to the Area EPS Operator's Transmission or Distribution System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment II: Description and Costs of the Distributed Energy Resource, Interconnection Facilities, and Metering Equipment

Equipment, including the Distribution Energy Resource, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer or the Area EPS Operator. The Area EPS Operator will provide a good faith estimate itemized cost, including administrative overheads, of its Interconnection Facilities and metering equipment, and a good faith estimate itemized cost of the annual operation and maintenance expenses associated with the Interconnection Facilities and metering equipment.

Attachment III: One-line Diagram Depicting the Distributed Energy Resource, Interconnection Facilities, and Metering Equipment, and Upgrades

Attachment IV: Milestones

The Milestones in line (1) below may be a calendar date. All other dates in this Attachment IV may be the number of Business Days from the calendar date in line (1) or from the completion of a different Milestone described in a specific number line. Similarly, the anticipated In-Service Date may be based on the number of Business Days from the completion of a specified line number.

In-Service Date: ___________________________________

Critical milestones and responsibilities as agreed to by the Parties:

	Milestone/Anticipated Date	Responsible Party
(1)	______________________________	____________________
(2)	______________________________	____________________
(3)	______________________________	____________________
(4)	______________________________	____________________
(5)	______________________________	____________________
(6)	______________________________	____________________
(7)	______________________________	____________________
(8)	______________________________	____________________
(9)	______________________________	____________________
(10)	______________________________	____________________
(11)	______________________________	____________________
(12)	______________________________	____________________
(13)	______________________________	____________________

Agreed to by:

Area EPS Operator	______________________	Date	__________
Transmission Owner (If Applicable)	______________________	Date	__________
Interconnection Customer	______________________	Date	__________

Attachment V: Additional Operating and Maintenance Requirements for the Area EPS Operator's Distribution System and Affected Systems Need to Support the Interconnection Customer's Needs

The Area EPS Operator shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the Area EPS Operator's Distribution System. Additional operating and maintenance requirements for an Affected System needed to support the Interconnection Customer's needs may be addressed in a separate agreement described in Section 14.6.

Attachment VI: Area EPS Operator’s Description of Distribution and Network Upgrades and Good Faith Estimates of Upgrade Costs

The Area EPS Operator shall describe Distribution and Network Upgrades and provide an itemized good faith estimate of the costs, including administrative overheads, of the Upgrade and annual operations and maintenance expenses associated with such Upgrades. The Area EPS Operator shall functionalize Upgrade costs and annual expenses as either transmission or distribution related. Additional Distribution or Network Upgrades required for an Affected System may be addressed in a separate agreement as described in Section 14.6.

Attachment VII: Assignment of Interconnection Agreement

This is an Assignment of Interconnection Agreement (“Agreement”).

There is an Interconnection Agreement, including any and all Attachments thereto including any and all amendments (“Agreement”) by and between The City of Olivia Municipal Utilities, a municipal utility existing under the laws of the State of Minnesota, (“Area EPS Operator”), and ____, (“Assignor”) originally signed by the Area EPS Operator on ___________________ for a Distributed Energy Resource (DER) described as follows:

<u>DER System Information</u>

Type of DER System: ______________________________

Capacity Rating of System (AC): ______________________________

Limited Capacity Rating (AC): ______________________________

Address of DER System: ______________________________

____

The Assignor intends to convey its interest in the above-referenced DER to _________________ __________________________ (“Assignee”), and the Assignor intends to assign the Agreement to the Assignee.

Upon the execution of this Assignment by the Assignor, Assignee and the Area EPS Operator, agree as follows:

1. **Capitalized Terms**. Capitalized terms used but not defined herein shall have the meanings set forth in the Agreement.

2. **Consent to Assignment**. The Assignor hereby irrevocably assigns the Agreement in all respects to the Assignee and the Assignee accepts the assignment thereof in all respects.

3. **Amendment to Agreement**. The Area EPS Operator consents to this assignment and, as assigned, the Agreement is hereby amended so that wherever the name of the Assignor

is used therein it shall mean the Assignee. It is further agreed that all terms and conditions of the Agreement, as amended by this Assignment, shall remain in full force and effect.

4. **Payments by Area EPS Operator**. Any and all payments made by Area EPS Operator under the Agreement to either the Assignor or the Assignee shall be deemed to have been made to both and shall discharge the Area EPS Operator from any further liability with regard to said payment.

5. **Financial Obligations of Assignor and Assignee**. Any and all financial liability, including but not limited to amounts due, from the Interconnection Customer to the Area EPS Operator, occurring or accruing under the Agreement on or before the date of the signature of the Area EPS Operator to this Assignment shall be deemed to be the obligation of both the Assignor and Assignee, and the Area EPS Operator may recover any such amounts jointly and severally from the Assignor and Assignee.

6. **Contact information**. The following information updates and replaces the designated information as set forth on page 1 of the Agreement, and in Section 28.1, 28.2, 28.3 and 28.4 of the Agreement.

Page 1 Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

28.1 General Notices. Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

28.2 Billing and Payment Notices. Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

28.3 Alternative Forms of Notices. Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

28.4 Designated Operating Representative. Interconnection Customer Information

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

____

Phone: ______________________________

Email: ______________________________

7. **Signatures.** Facsimile or electronic signatures, or signatures to this Assignment sent electronically, shall have the same effect as original signatures. Photocopies, or electronically stored versions of this Assignment, shall have the same validity as the original.

The Area EPS Operator, Assignor, and Assignee have executed this Assignment as of the dates as set forth below.

Assignor

[Insert legal name of Assignor]

____

Signed: ____

Name (Printed): ____

Title: ____

Date: ______________________________

Assignee

[Insert legal name of Assignee]

____

Signed: ____

Name (Printed): ____

Title: ____

Date: ______________________________

Area EPS Operator

[Insert legal name of Area EPS Operator]

____

Signed: ____

Name (Printed): ____

Title: ____

Date: ______________________________

Minnesota Municipal Power Agency

Distributed Generation Tariff

The long term contractual arrangements between the Minnesota Municipal Power Agency (MMPA) and its members do not allow for a member to purchase directly from another entity. Therefore, MMPA is offering to purchase the output of generation offered for sale by a member's customer ("Customer"). MMPA has adopted rates, terms, and conditions of this tariff ("Tariff") as a means of making such purchases from the Customer.

Availability
Available to Customers who (i) have a generator that is interconnected to an MMPA member's distribution system ("Distributed Generation" or "DG"), (ii) have such generator with a nameplate capacity of at least 40 kW but no more than 10 MW, (iii) offer to sell their output on a short term and (iv) meet the qualifications set forth below.

Qualifications

1. The DG facility must be fueled by natural gas (or another similarly clean fuel) or be a renewable energy resource as defined under state regulation.
2. The DG facility must be a generator that is able to put power onto the member's grid at any time – not just when a service interruption occurs – and in phase with the electricity distributed by the member.
3. The DG facility must be an operable, permanently installed generator that is owned and operated by the customer receiving retail electric service from the member at the same site.
4. The DG facility output must be separate and distinct from the retail customer load. No net billing will be provided.

Interconnection and Metering
A Customer seeking to connect its DG facility to the member's distribution system must follow the "City of Olivia Municipal Utilities Distributed Energy Resource Interconnection Process." All costs of the interconnection, including those incurred by the member and MMPA, shall be borne by the Customer.

A Customer shall have metering of the generator output at the point of interconnection with the member distribution system. Such metering must meet the meter requirements of MMPA and the Midwest Independent System Operator ("MISO"). Metering data must be accessible by MMPA. The costs of metering and all communication devices, including user fees, shall be borne by the Customer.

The MMPA members will maintain a copy of these procedures at their websites.

Must-Buy
MMPA shall purchase all the DG facility output offered for sale by the Customer.

Contract
The Customer will be required to enter into a contract with MMPA. The form of contract is provided as Attachment A hereto.

Contract Term
The contract term shall start on the first of the month following acceptance of the DG facility's registration in MISO. The contract term shall end on the date that registration in MISO is no longer effective, but such end date shall be no greater than one year after the start date of the Contract Term. If the Customer desires a contract term greater than one year, the Customer and MMPA will negotiate an individual contract which is outside of the rates, terms and conditions of this Tariff.

Payments
Payments to the Customer for generation output shall be as described below and on Attachment B hereto.

Energy Delivery Schedule
The Customer will be required to submit an energy delivery schedule for the DG facility to MMPA by 8:00 a.m. prevailing time each business day. The schedule is to be for a consecutive 7-day period, starting at midnight on the day of schedule notification. MMPA will factor such schedule into its demand forecast and energy demand bid to the MISO.

Outages
The Customer will provide to MMPA an annual planned outage schedule by September 30 of each year. The Customer will notify MMPA of any unplanned outage within 5 minutes of being completely off-line.

Standby Service
The Customer is not required to buy standby power to meet the station service requirements of the DG facility when off-line. However, if standby power is not purchased, it may not be available. Any standby service the Customer elects to take must be at the member's current rate for standby service. Such service will be contracted directly with the applicable MMPA member.

Changes to Rates, Terms and Conditions
This Tariff is dependent on the provisions of the MISO tariff and the Resource Adequacy Business Practices Manual (together, the "MISO Rules") concerning Load Modifying Resources. Any changes thereto will automatically carry forward to this Tariff and shall become effective on the date of effectiveness of such changes under the MISO tariff.

ATTACHMENT A

This agreement ("Service Agreement") is made by and between Minnesota Municipal Power Agency ("MMPA" or "Buyer"), ____________________ (___ or "Member") and ____________________ (___ or "Customer") and is effective as of the date of the signatures below (each individually a "party", together, the "parties").

WHEREAS Buyer has a Distributed Generation Tariff ("Tariff") under which it may purchase products from a generator facility connected at the distribution voltage level on the Member system; and

WHEREAS Customer owns and operates a generator facility connected to the distribution voltage level of the Member system ("DG facility"); and

WHEREAS Customer wishes to sell the output of the DG facility to MMPA under the rates, terms and conditions of the Tariff.

NOW THEREFORE, the parties covenant and agree to the following:

1. The DG facility information shown on the attached Exhibit 1 is accurate as of the date below.
2. The DG facility meets all of the requirements of the Tariff.
3. Customer will sell the output of the DG facility in accordance with the provisions of the Tariff.
4. Buyer will purchase the output of the DG facility from Customer and make payments to Customer in accordance with the provisions of the Tariff.
5. Buyer and Member have determined that Customer is entitled to Credits in the form of additional payments to Customer as follows:
6. Any disputes will be resolved by the senior representatives of the parties.
7. Other:

IN WITNESS WHEREOF, the parties have executed this Service Agreement through their duly authorized officers as of the date set forth below.

MMPA ____

Name, Title and Date

Member ____

Name, Title and Date

Customer ____

Name, Title and Date

EXHIBIT 1
to
Service Agreement

Name of Facility:

Location:

Name Plate Rating:

Type of Facility:

Fuel Source:

Interconnection Point:

Meter Number and Location:

Accreditation Test date:

24 Hour Contact for DG Facility:

ATTACHMENT B

MMPA will make payments to the Customer for Zonal Resource Credits and Energy. MMPA may reduce payments to the Customer or render charges to the Customer for failure to deliver energy when called upon by MISO.

“Credits” in the form of additional payments may be provided to the Customer in recognition of any benefits the DG facility provides to the MMPA member distribution system or to MMPA.

Payments by MMPA to a Customer will be net of the above and made within thirty (30) days after the end of the month in which service was provided to MMPA.

<u>Zonal Resource Credits</u>

The DG facility may receive recognition for the capacity it may provide to the MISO system. That recognition is now known as a Zonal Resource Credit (ZRC, as defined in the MISO rules) and is determined by the facility’s Unforced Capacity (UCAP, as defined in the MISO rules). The UCAP methodology is implemented to address the fact that not all DG facilities contribute equally to reliability and will differ according to the resource characteristics of the DG facility (intermittency, fuel type, etc.).

The UCAP used to determine ZRCs for the DG facility will be based on the application of then effective MISO rules and the test results for the facility.

In order to maintain one’s ZRC benefit, the DG facility must be:

- Claimed only by MMPA,
- Greater or equal to 100kW
- Schedulable by MISO or the Local Balancing Authority (LBA, as defined in the MISO rules) within 12 hours’ notice,
- Able to respond to MISO calls for energy dispatch at least 5 times as specified by MISO rules for emergency event purposes, and
- Able to sustain energy production for a minimum of 4 consecutive hours.

Additional qualification requirements may apply to the DG facility as listed in the MISO rules. The DG facility must be reviewed for accreditation as a Load Modifying Resource on an annual basis.

MMPA shall pay the Customer each month an amount equal to the product of:

(ii) the ZRC quantity of the generator facility as qualified by MISO for such month, and

(iii) the value of a ZRC as determined by the MISO Planning Resource Auction (PRA, as defined in the MISO rules) for such month.

In the event that MISO calls upon the DG facility to deliver energy to the distribution system during a MISO emergency, and the DG facility does not respond timely, then MMPA may impose a penalty on the Customer equal to the sum of the penalties for each failure hour during the month, determined by the product of:

(i) the amount of energy not delivered during such hour,
(ii) the Real Time (RT), Ex Post Locational Marginal Price (LMP) for the DG facility location as determined by MISO for such hour, and
(iii) 1.15, to recognize costs such as MISO Revenue Sufficiency Guarantee (RSG), MISO and MMPA administration costs, etc.

MMPA has the right to terminate any Service Agreement under this Tariff if Customer fails to produce requested energy when called upon by MISO more than once in a calendar year.

Energy

MMPA shall pay the Customer each month an amount equal to the sum of the payments for each delivery hour during the month, determined by the product of:

(i) the amount of energy delivered by the metered DG facility at the point of interconnection for such hour,
(ii) The RT, LMP for the DG facility location as determined by MISO, and
(iii) 0.85 to account for RSG costs, MISO and MMPA administration costs, etc.

Credits

The following credits in the form of additional payments may apply:

(i) Distribution Credits – a Customer may receive a credit equal the member's avoided distribution costs resulting from the installation of the DG facility, as determined by the member.

(ii) Line Loss Credits – a Customer may request the member to provide a specific line loss study and receive line loss credits if the study supports such credits in the member's sole opinion. The Customer is responsible for the cost of the study regardless of the study's outcome.

(iii) Renewable Energy Credit – a Customer may receive this credit if it is a renewable energy resource as defined under state regulations. The credit will vary based on DG facility output and market prices (as determined by an independent party) and account for administrative costs incurred by MMPA in getting the DG facility recognized in the Midwest Renewable Energy Tracking System.

City of Olivia, Minnesota
Resolution 2019-53

A resolution adopting The City of Olivia Municipal Utilities' Policy Regarding Distributed Energy Resources and Net Metering and Rules Governing the Interconnection of Cogeneration and Small Power Production Facilities.

WHEREAS, the City is served by The City of Olivia Municipal Utilities, which is committed to providing customers with reliable and affordable power.

WHEREAS, the purpose of this Distributed Energy Resources and Net Metering Policy is to establish the qualification criteria and certain responsibilities for the delivery, interconnection, metering, and purchase of electricity from distributed generation facilities.

WHEREAS, this policy, in accordance with Minnesota Statutes §216B.164, shall be implemented to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the utility's ratepayers and the public.

WHEREAS, the purpose of the Cogeneration and Small Power Production Rules is for The City of Olivia Municipal Utilities to implement certain provisions of Minnesota Statutes §216B.164, the Public Utility Regulatory Policies Act of 1978, and Federal Energy Regulatory Commission regulations related to customer-owned distributed energy resources.

WHEREAS, the adoption of these rules establishes that the Olivia City Council is the interpreting body and arbiter of the provisions of Minnesota Statutes §216B.164 for The City of Olivia Municipal Utilities.

WHEREAS, The City of Olivia Municipal Utilities shall annually file a cogeneration and small power production tariff with The Olivia City Council under these rules.

WHEREAS, the cogeneration and small power production tariff shall include a calculation of average retail utility energy rates, standard contracts to be used with qualifying facilities, interconnection process and technical requirements, and The City of Olivia Municipal Utilities' estimated average incremental energy costs and net annual avoided capacity costs.

WHEREAS, all filings under these rules shall be maintained at the City offices and shall be made available for public inspection during normal business hours.

THEREFORE, BE IT RESOLVED that the Olivia City Council adopts the following Policy Regarding Distributed Energy Resources and Net Metering and Rules Governing the Interconnection of Cogeneration and Small Power Production Facilities.

Adoption by the City Council of the City of Olivia on this 3rd day of June, 2019.

Suzanne D. Hilgert

Suzanne Hilgert, Mayor

ATTEST:

Daniel Coughlin

Dan Coughlin, City Administrator

City of Olivia Municipal Utilities
Policy
Regarding Distributed Energy Resources
and Net Metering

To establish the application procedure and qualification criteria for all customers for the delivery, interconnection, metering and purchase of electricity from distributed energy resource facilities and to comply with applicable laws and rules governing distributed energy resources.

The utility recognizes its obligation to provide interconnection to eligible qualifying facilities and will comply with all applicable laws and rules governing distributed energy resources.

For purposes of this policy, the following terms have the meanings given them:

A. **Average retail energy rate** - the average of the retail energy rates, exclusive of special rates based on income, age, or energy conservation, according to the applicable rate schedule of the utility for sales to the class of customer of which the customer/qualifying facility belongs.
B. **Avoided costs** - the incremental costs to the utility of electric energy or capacity or both which, but for the purchase from the qualifying facility, the utility would generate itself or purchase from another source.
C. **Contract** - the written agreement between the customer/qualifying facility and the utility, as established in the utility's Rules Governing Interconnection of Cogeneration and Small Power Production.
D. **Distributed energy resource (DER)** - a distributed generation system incorporated with or without an electric storage system.
E. **Interconnection application** - the form to be used by the customer to submit its formal request for interconnection to the utility and which shall be substantially similar in form to that contained in the Distributed Energy Resources Interconnection Process adopted by the utility.
F. **Interconnection rules** - any applicable rules developed in accordance with Minnesota Statutes §§216B.164 and 216B.1611. This includes the utility's Rules Governing Interconnection of Cogeneration and Small Power Production. It also includes the utility's Distributed Energy Resources Interconnection Process which includes its Simplified Process, Fast Track Process, and Study Process as well as the technical requirements incorporated therein or any future technical requirements adopted by the utility.
G. **Measured capacity** - for purposes of determining capacity, it shall be measured based on the highest fifteen (15) minute average demand of the unit in any one billing period.
H. **Net metering/net billing** - the process whereby the customer and the utility compensate each other based on the difference in the amount of energy each sells to the other at the net metered facility.
I. **Net metered facility** - an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy or high efficiency generation sources with a capacity of less than 40 kilowatts that has elected in writing to be compensated for excess generation through net metering/net billing.
J. **Total generator nameplate capacity** - the nominal voltage (V), current (A), maximum active power (kWac), apparent power (kVA), and reactive power (kvar) at which a distributed energy resource (DER), is capable of sustained operation. For a qualifying facility with multiple units, the total generator capacity is equal to the sum of all individual DER units' nameplate rating in the qualifying facility. The DER system's total generation capacity may,

with the utility’s agreement, be limited thought use of control systems, power relays or similar device settings or adjustments as identified in IEEE 1547. The customer must fully, accurately and completely disclose in its interconnection application to the utility, the technical specifications for any capacity limiting device contemplated and the customer shall furnish the utility with any factory manuals or other similar documents requested from the utility regarding such limiting or other control devices which factor into the calculation of total generator capacity.

K. **Qualifying facility** - a cogeneration or small power production facility which satisfies the conditions established in Code of Federal Regulations, title 18, part 292. The qualifying facility must be owned by a customer of the utility and located in the utility service area.

L. **Utility –** City of Olivia Municipal Utilities.

In the event an inconsistency exists between terms in this policy and those established by applicable statute, rule or court order, then the definition so established shall supersede the definition used in this policy and shall govern.

All customers are eligible for distributed generation, interconnection with the utility's distribution system and application of net metering upon the following terms and conditions.

1. The customer must meet the eligibility requirements set forth in the federal Public Utility Regulatory Policies Act of 1978 (PURPA) *18 C.F.R. 292.303, 292.304 and Minnesota's distributed generation laws. Minn. Stat. §216B.164.
2. The customer shall complete, sign and return to utility either the Interconnection Application or the Simplified Process Application in the form prescribed in the utility’s Distributed Energy Resources Interconnection Process. The application shall be approved by the utility prior to the customer beginning the project. The customer signature on the application indicates the customer shall follow the steps outlined in the utility’s interconnection rules.
3. The customer shall enter into a written contract with the utility using the uniform contract contained in the utility’s Rules Governing Interconnection of Cogeneration and Small Power Production.
4. The qualifying facility shall pay the utility for all reasonable costs of interconnection including those costs outlined in Minnesota Statute 216B.164, the utility’s DER Interconnection Process, and the State of Minnesota Interconnection Technical Requirements.
5. The qualifying facility’s total generator nameplate capacity shall be less than 40 kW and the facility shall operate at a measured capacity of less than 40 kW at all times to qualify for net metering/net billing or roll over credit compensation.
6. The utility may limit the capacity and operating characteristics of qualifying facility single phase generators in a manner consistent with the utility limitations for single phase motors, when necessary to avoid a qualifying facility from causing problems with the service of other customers.
7. The utility may require the qualifying facility to discontinue parallel generation operations when necessary for system safety.

8. The power output from the qualifying facility must be maintained so that frequency and voltage are compatible with normal utility service and do not cause that service to fall outside the prescribed limits of interconnection rules and other standard limitations.
9. The qualifying facility shall keep in force liability insurance against personal or property damage due to the installation, interconnection, and operation of its electric generating facilities. The amount of insurance coverage shall be the maximum amount of said insurance for a qualifying facility or net metered facility as outlined in the utility's DER Interconnection Process.
10. Failure of the qualifying facility to operate its distributed energy resource at a measured capacity below the 40 kW AC capacity limit established by Minn. Stat. §216B.164, Sub. 3 and as contemplated by this policy, shall result in the following. The utility will notify the customer/qualifying facility of the fact that its generating equipment has failed to operate below the 40 kW AC maximum capacity and will provide the customer/qualifying facility with the date, time and kW reading that substantiate this finding.
11. The utility shall compensate the customer/qualifying facility for all metered electricity produced by said qualifying facility during the thirty (30) day period during which the failure occurred, at the utility's wholesale power supplier's avoided cost rate.
12. The utility shall continue to pay the customer/qualifying facility for subsequent electricity produced and delivered pursuant to the contract, at the utility's wholesale power supplier's avoided cost rate until:
    1. The problem with the generator that caused it to operate at or above the statutory maximum capacity has been remedied; and
    2. The utility has been provided documentation adopted by a Minnesota Professional Engineer that confirms the problem with the generator has been remedied.
13. Any customer account eligible for net metering/net billing is not eligible for any other load management discounts unless agreed to by the utility.
14. Payment for the purchase of the qualifying facility's electricity herein shall be in the form of a credit on the customer's monthly billing invoice or paid by check or electronic payment to the customer within fifteen (15) days of the billing date, whichever is selected and indicated in the contract.
15. The customer must be, and continue to be, current with payment on its electric account with utility.
16. The customer must not enter into any arrangement that violates the utility's exclusive right to provide electric service in its service area under Minnesota Statutes §§216B.37-44.
17. In the event that the distributed generator fails to meet the requirements of this policy for a total distributed generation capacity of less than 40 kW AC, and fails to satisfy the corrective requirements set forth in Section 12 above, then the utility will have the right to (1) cancel the contract with the owner of the qualifying facility, and (2) enter into a new contract with the owner of the qualifying facility that, among other changes, adjusts the qualifying facility's rated capacity and specifies avoided cost pricing for the qualifying facility's output. To the extent that the utility does not have the obligation to make purchases from qualifying facilities of 40 kW or greater due to transfer of the obligation to the utility's wholesale supplier that has been approved by the Federal Energy Regulatory Commission, the new agreement will be between the utility's wholesale supplier and the

qualifying facility. In either case, the utility (and, as applicable, the utility's wholesale supplier) and the owner of the qualifying facility will cooperate in the transition from the form of contract set forth in the utility's Rules Governing Interconnection of Cogeneration and Small Power Production to a new form of contract appropriate to a qualifying facility with a capacity of 40 kW or greater.

18. Fully executed interconnection contracts for distributed energy resources may be canceled in the event the distributed energy resource fails to interconnect to the utility's distribution system within twelve (12) months of signing of the interconnection contract by the qualifying facility and the utility.

Rules

Governing the Interconnection of

Cogeneration and Small Power Production Facilities

with

City of Olivia Municipal Utilities

Part A. DEFINITIONS

Subpart 1. Applicability. For purposes of these rules, the following terms have the meanings given them below.

Subp. 2. Average retail utility energy rate. "Average retail utility energy rate" means, for any class of utility customer, the quotient of the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales. The computation shall use data from the most recent calendar year available.

Subp. 3. Backup power. "Backup power" means electric energy or capacity supplied by the utility to replace energy ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the facility.

Subp. 4. Capacity. "Capacity" means the capability to produce, transmit, or deliver electric energy, and is measured by the number of megawatts alternating current at the point of common coupling between a qualifying facility and the utility's electric system during a 15-minute interval period.

Subp. 5. Capacity costs. "Capacity costs" means the costs associated with providing the capability to deliver energy. The utility capacity costs consist of the costs of facilities from the utility and the utility’s wholesale provider used to generate, transmit, and distribute electricity and the fixed operating and maintenance costs of these facilities.

Subp. 6. Customer. "Customer" means the person named on the utility electric bill for the premises.

Subp. 7. Energy. "Energy" means electric energy, measured in kilowatt-hours.

Subp. 8. Energy costs. "Energy costs" means the variable costs associated with the production of electric energy. They consist of fuel costs and variable operating and maintenance expenses.

Subp. 9. Firm power. "Firm power" means energy delivered by the qualifying facility to the utility with at least a 65 percent on-peak capacity factor in the month. The capacity factor is based upon the qualifying facility's maximum metered capacity delivered to the utility during the on-peak hours for the month.

Subp. 10. Governing body. “Governing body” means the Olivia City Council.

Subp. 11. Interconnection costs. "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the utility that are directly related to installing and maintaining the physical facilities necessary to permit interconnected operations with a qualifying facility. Costs are considered interconnection costs only to the extent that they exceed the costs the utility would incur in selling electricity to the qualifying facility as a nongenerating customer.

Subp. 12. Interruptible power. "Interruptible power" means electric energy or capacity supplied by the utility to a qualifying facility subject to interruption under the provisions of the utility's tariff applicable to the retail class of customers to which the qualifying facility would belong irrespective of its ability to generate electricity.

Subp. 13. Maintenance power. "Maintenance power" means electric energy or capacity supplied by a utility during scheduled outages of the qualifying facility.

Subp. 14. On-peak hours. "On-peak hours" means either those hours formally designated by the utility as on-peak for ratemaking purposes or those hours for which its typical loads are at least 85 percent of its average maximum monthly loads.

Subp. 15. Point of distributed energy resource (DER) connection. "Point of DER connection" means the point where the qualifying facility's generation system, including the point of generator output, is connected to the customer’s electric system and meets the current definition of IEEE 1547.

Subp. 16. Purchase. "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by the utility or its agent.

Subp. 17. Qualifying facility. "Qualifying facility" means a cogeneration or small power production facility which satisfies the conditions established in Code of Federal Regulations, title 18, part 292. The initial operation date or initial installation date of a cogeneration or small power production facility must not prevent the facility from being considered a qualifying facility for the purposes of this chapter if it otherwise satisfies all stated conditions. The qualifying facility must be owned by a Customer and located in the utility service area.

Subp. 18. Sale. "Sale" means the sale of electric energy or capacity or both by the utility to a qualifying facility.

Subp. 19a. Standby charge. "Standby charge" means the charge imposed by the utility upon a qualifying facility for the recovery of costs for the provision of standby services necessary to make electricity service available to the qualifying facility.

Subp. 19b. Standby service. "Standby service" means the service to potentially provide electric energy or capacity supplied by the utility to a qualifying facility greater than 40 kW.

Subp. 20. Supplementary power. "Supplementary power" means electric energy or capacity supplied by the utility which is regularly used by a qualifying facility in addition to that which the facility generates itself.

Subp. 21. System emergency. "System emergency" means a condition on the utility's system which is imminently likely to result in significant disruption of service to customers or to endanger life or property.

Subp. 22. Utility. "Utility" means City of Olivia Municipal Utilities.

Part B. SCOPE AND PURPOSE

The purpose of these rules is to implement certain provisions of Minnesota Statutes, §216B.164; the Public Utility Regulatory Policies Act of 1978, United States Code, title 16, §824a-3; and the Federal Energy Regulatory Commission regulations, Code of Federal Regulations, title 18, part 292. These rules shall be applied in accordance with their intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public.

Part C. FILING REQUIREMENTS

Annually the utility shall file for review and approval, a cogeneration and small power production tariff with the governing body. The tariff must contain schedules 1 – 4.

SCHEDULE 1.

Schedule 1 shall contain the calculation of the average retail utility energy rates to be updated annually.

SCHEDULE 2.

Schedule 2 shall contain all standard contracts to be used with qualifying facilities, containing applicable terms and conditions.

SCHEDULE 3.

Schedule 3 shall contain the utility's adopted interconnection process, safety standards, technical requirements for distributed energy resource systems, required operating procedures for interconnected operations, and the functions to be performed by any control and protective apparatus.

SCHEDULE 4.

Schedule 4 shall contain the estimated average incremental energy costs by seasonal, peak and off-peak periods for the utility's power supplier from which energy purchases are first avoided. Schedule 4 shall also contain the net annual avoided capacity costs, if any, stated per kilowatt-hour and averaged over the on-peak hours and over all hours for the utility's power supplier from which capacity purchases are first avoided. Both the average incremental energy costs and net annual avoided capacity costs shall be increased by a factor equal to 50 percent of the utility and the utility's power supplier's overall line losses due to distribution, transmission and transformation of electric energy.

Part D. AVAILABILITY OF FILINGS

All filings shall be maintained at the utility's general office and any other offices of the utility where rate tariffs are kept. The filings shall be made available for public inspection during normal business hours. The utility shall supply the current year's distributed generation rates, interconnection procedures and application form on the utility website, if practicable, or at the utility office.

Part E. REPORTING REQUIREMENTS

Annually the utility shall report to the governing body for its review and approval an annual report including information in subparts 1-3. The utility shall still comply with other federal and state reporting of distributed generation to federal and state agencies expressly required by statute.

Subpart 1. Summary of average retail utility energy rate. A summary of the qualifying facilities that are currently served under average retail utility energy rate.

Subp. 2. Other qualifying facilities. A summary of the qualifying facilities that are not currently served under average retail utility energy rate.

Subp. 3. Wheeling. A summary of the wheeling undertaken with respect to qualifying facilities.

Part F. CONDITIONS OF SERVICE

Subpart 1. Requirement to purchase. The utility or its agent shall purchase energy and capacity from any qualifying facility which offers to sell energy and capacity to the utility and agrees to the conditions in these rules.

Subp. 2. Written contract. A written contract shall be executed between the qualifying facility and the utility or its agent.

Part G. ELECTRICAL CODE COMPLIANCE

Subpart 1. Compliance; standards. The interconnection between the qualifying facility and the utility must comply with the requirements in the most recently published edition of the National Electrical Safety Code issued by the Institute of Electrical and Electronics Engineers. The interconnection is subject to subparts 2 and 3.

Subp. 2. Interconnection. The qualifying facility is responsible for complying with all applicable local, state, and federal codes, including building codes, the National Electrical Code (NEC), the National Electrical Safety Code (NESC), and noise and emissions standards. The utility shall require proof that the qualifying facility is in compliance with the NEC before the interconnection is made. The qualifying facility must obtain installation approval from an electrical inspector recognized by the Minnesota State Board of Electricity.

Subp. 3. Generation system. The qualifying facility's generation system and installation must comply with the American National Standards Institute/Institute of Electrical and Electronics Engineers (ANSI/IEEE) standards applicable to the installation.

Part H. RESPONSIBILITY FOR APPARATUS

The qualifying facility, without cost to the utility, must furnish, install, operate, and maintain in good order and repair any apparatus the qualifying facility needs in order to operate in accordance with schedule 3.

Part I. TYPES OF POWER TO BE OFFERED; STANDBY SERVICE

Subpart 1. Service to be offered. The utility shall offer maintenance, interruptible, supplementary, and backup power to the qualifying facility upon request.

Subp. 2. Standby service. The utility shall offer a qualifying facility standby power or service at the utility's applicable standby rate schedule.

Part J. DISCONTINUING SALES DURING EMERGENCY

The utility may discontinue sales to the qualifying facility during a system emergency, if the discontinuance and recommencement of service is not discriminatory.

Part K. RATES FOR UTILITY SALES TO A QUALIFYING FACILITY

Rates for sales to a qualifying facility are governed by the applicable tariff for the class of electric utility customers to which the qualifying facility belongs or would belong were it not a qualifying facility. Such rates are not guaranteed and may change from time to time at the discretion of the utility.

Part L. STANDARD RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Subpart 1. Qualifying facilities with 100-kilowatt capacity or less. For qualifying facilities with capacity of 100 kilowatts or less, standard purchase rates apply. The utility shall make available four types of standard rates, described in parts M, N, O, and P. The qualifying facility with a capacity of 100 kilowatts or less must choose interconnection under one of these rates, and must specify its choice in the written contract required in part V. Any net credit to the qualifying facility must, at its option, be credited to its account with the utility or returned by check or comparable electronic payment service within 15 days of the billing date. The option chosen must be specified in the written contract required in part V. Qualifying facilities remain responsible for any monthly service charges and demand charges specified in the tariff under which they consume electricity from the utility.

Subp. 2. Qualifying facilities over 100-kilowatt capacity. A qualifying facility with more than 100-kilowatt capacity has the option to negotiate a contract with the utility or, if it commits to provide firm power, be compensated under standard rates.

Subp. 3. Grid access charge. A qualifying facility shall be assessed a monthly grid access charge to recover the fixed costs not already paid by the customer through the customer's existing billing arrangement. The additional charge shall be reasonable and appropriate for the class of customer based on the most recent cost of service study defining the grid access charge. The cost of service study for the grid access charge shall be made available for review by the customer of the utility upon request.

Part M. AVERAGE RETAIL UTILITY ENERGY RATE

Subpart 1. Applicability. The average retail utility energy rate is available only to customer-owned qualifying facilities with capacity of less than 40 kilowatts which choose not to offer electric power for sale on either a time-of-day basis, a simultaneous purchase and sale basis or roll-over credit basis.

Subp. 2. Method of billing. The utility shall bill the qualifying facility for the excess of energy supplied by the utility above energy supplied by the qualifying facility during each billing period according to the utility's applicable retail rate schedule.

Subp. 3. Additional calculations for billing. When the energy generated by the qualifying facility exceeds that supplied by the utility to the customer at the same site during the same billing period, the utility shall compensate the qualifying facility for the excess energy at the average retail utility energy rate.

Part N. SIMULTANEOUS PURCHASE AND SALE BILLING RATE

Subpart 1. Applicability. The simultaneous purchase and sale rate is available only to qualifying facilities with capacity of less than 40 kilowatts which choose not to offer electric power for sale on average retail utility energy rate basis, time-of-day basis or roll- over credit basis.

Subp. 2. Method of billing. The qualifying facility must be billed for all energy and capacity it consumes during a billing period according to the utility's applicable retail rate schedule.

Subp. 3. Compensation to qualifying facility; energy purchase. The utility shall purchase all energy which is made available to it by the qualifying facility. At the option of the qualifying facility, its entire generation must be deemed to be made available to the utility. Compensation to the qualifying facility must be the energy rate shown on schedule 4.

Subp. 4. Compensation to qualifying facility; capacity purchase. If the qualifying facility provides firm power to the utility, the capacity component must be the utility's net annual avoided capacity cost per kilowatt-hour averaged over all hours shown on schedule 4, divided by the number of hours in the billing period. If the qualifying facility does not provide firm power to the utility, no capacity component may be included in the compensation paid to the qualifying facility.

Part O. TIME-OF-DAY PURCHASE RATES

Subpart 1. Applicability. Time-of-day rates are required for qualifying facilities with capacity of 40 kilowatts or more and less than or equal to 100 kilowatts, and they are optional for qualifying facilities with capacity less than 40 kilowatts. Time-of-day rates are also optional for qualifying facilities with capacity greater than 100 kilowatts if these qualifying facilities provide firm power.

Subp. 2. Method of billing. The qualifying facility must be billed for all energy and capacity it consumes during each billing period according to the utility's applicable retail rate schedule.

Subp. 3. Compensation to qualifying facility; energy purchases. The utility shall purchase all energy which is made available to it by the qualifying facility. Compensation to the qualifying facility must be the energy rate shown on schedule 4.

Subp. 4. Compensation to qualifying facility; capacity purchases. If the qualifying facility provides firm power to the utility, the capacity component must be the capacity cost per kilowatt shown on schedule 4 divided by the number of on-peak hours in the billing period. The capacity component applies only to deliveries during on-peak hours. If the qualifying facility does not provide firm power to the utility, no capacity component may be included in the compensation paid to the qualifying facility.

Part P. ROLL-OVER CREDIT PURCHASE RATES

Subpart 1. Applicability. The roll-over credit rate is available only to qualifying facilities with capacity of less than 40 kilowatts which choose not to offer electric power for sale on average retail utility energy rate basis, time-of-day basis or simultaneous purchase and sale basis.

Subp. 2. Method of billing. The utility shall bill the qualifying facility for the excess of energy supplied by the utility above energy supplied by the qualifying facility during each billing period according to the utility's applicable retail rate schedule.

Subp. 3. Additional calculations for billing. When the energy generated by the qualifying facility exceeds that supplied by the utility during a billing period, the utility shall apply the excess kilowatt hours as a credit to the next billing period kilowatt hour usage. Excess kilowatt hours that are not offset in the next billing period shall continue to be rolled over to the next consecutive billing period. Any excess kilowatt hours rolled over that are remaining at the end of each calendar year shall cancel with no additional compensation.

Part Q. CONTRACTS NEGOTIATED BY CUSTOMER

A qualifying facility with capacity greater than 100 kilowatts must negotiate a contract with the utility setting the applicable rates for payments to the customer of avoided capacity and energy costs.

Subpart 1. Amount of capacity payments. The qualifying facility which negotiates a contract under part Q must be entitled to the full avoided capacity costs of the utility's wholesale power provider, the Minnesota Municipal Power Agency. The amount of capacity payments will be determined by the utility and the utility's wholesale power provider.

Subp. 2. Full avoided energy costs. The qualifying facility which negotiates a contract under part Q must be entitled to the full avoided energy costs of the utility's wholesale power provider, the Minnesota Municipal Power Agency. The costs must be adjusted as appropriate to reflect line losses.

Part R. WHEELING

Qualifying facilities with capacity of 30 kilowatts or greater, are interconnected to the utility's distribution system and choose to sell the output of the qualifying facility to any other utility, must pay any appropriate wheeling charges to the utility. Within 15 days of receiving payment from the utility ultimately receiving the qualifying facility's output, the utility shall pay the qualifying facility the payment less the charges it has incurred and its own reasonable wheeling costs.

Part S. NOTIFICATION TO CUSTOMERS

Subpart 1. Contents of written notice. Following each annual review and approval by the utility of the cogeneration rate tariffs the utility shall furnish in the monthly newsletter or similar mailing, written notice to each of its customers that the utility is obligated to interconnect with and purchase electricity from cogenerators and small power producers.

Subp. 2. Availability of information. The utility shall make available to all interested persons upon request, the interconnection process and requirements adopted by the utility, pertinent rate schedules and sample contractual agreements.

Part T. DISPUTE RESOLUTION

In case of a dispute between a utility and a qualifying facility or an impasse in the negotiations between them, either party may request the governing body to determine the issue.

Part U. INTERCONNECTION CONTRACTS

Subpart 1. Interconnection standards. The utility shall provide a customer applying for interconnection with a copy of, or electronic link to, the utility's adopted interconnection process and requirements.

Subp. 2. Existing contracts. Any existing interconnection contract executed between the utility and a qualifying facility with capacity of less than 40 kilowatts remains in force until terminated by mutual agreement of the parties or as otherwise specified in the contract. The governing body has assumed all dispute responsibilities as listed in existing interconnection contracts. Disputes are resolved in accordance with Part T.

Subp. 3. Renewable energy credits; ownership. Generators own all renewable energy credits unless other ownership is expressly provided for by a contract between a generator and the utility.

Part V. UNIFORM CONTRACT

The form for uniform contract that shall be used between the utility and a qualifying facility having less than 40 kilowatts of capacity is as shown in subpart 1.

Subpart 1. Uniform Contract for Cogeneration and Small Power Production Facilities. (See attached contract form.)

Detroit Lakes Public Utility's 29.3 kW Select Solar Community Solar Garden
Detroit Lakes, MN

INTERCONNECTION PROCESS

Process Overview

ABSTRACT

Information for interconnecting all Distributed Energy Resources smaller than 10 megawatts in size to the utility distribution system.

Contents

Foreword

The State of Minnesota currently has interconnection process standards in effect to address the interconnection of Distributed Energy Resources (DER) to the distribution grid. Under Minnesota Statute §216B.1611, cooperatives and municipals shall adopt an interconnection process that addresses the same issues as the interconnection process approved by the Minnesota Public Utilities Commission. The City of Olivia Distributed Energy Resources Interconnection Process (Interconnection Process) applies to any DER no larger than 10-megawatts (MW) AC interconnecting to and operating in parallel with The City of Olivia Municipal Utilities' distribution system in Minnesota. This interconnection process document is designed to be customer-centric when explaining the steps and details to interconnect DER systems to the distribution grid.

The Interconnection Process is comprised of four manuals: 1) Process Overview, 2) Simplified Process, 3) Fast Track Process, and 4) Study Process and also contains several forms, including a final Interconnection Agreement. For the majority of DER interconnections, only the Process Overview and the Simplified Process manuals will apply. For larger and more complex DER interconnections, the Fast Track Process or the Study Process may apply.

As part of the Interconnection Process, an Interconnection Agreement is to be executed prior to interconnecting a DER system to the utility distribution grid. For most DER interconnections under 40kW, the utility's Contract for Cogeneration and Small Power Production Facilities (Uniform Contract) will be used. For DER systems that do not fall under the terms of the Uniform Contract, the Municipal Minnesota Interconnection Agreement (MMIA) will apply. For DER interconnections 40kW and larger, The City of Olivia appoints MMPA as the purchasing agent and will use the Minnesota Municipal Power Agency Distributed Generation Tariff in conjunction with the MMIA.

The process to interconnect a DER system to the distribution grid starts with the submission of an Interconnection Application. Each track has different information that is requested in the application and the non-refundable interconnection application fees will vary. Both the electric utility and the interconnecting customer have timelines that are enforced to ensure a timely application review, contract execution and interconnection commissioning.

The key to a successful interconnection of a DER system is communication between all parties. Timely submission of the Interconnection Application prior to the purchase and installation of a DER system is strongly recommended. The Utility encourages customers to ask questions throughout the interconnection process. Interconnecting DER system to the distribution grid is not an effortless process, but it does not need to be a problematic process either.

1 Key Terminology

1.1. Distributed Energy Resource

Distributed Energy Resources, DER, were often referred to in past interconnection processes as Distributed Generation, DG, and on occasion also interchanged with the term Qualifying Facility, QF. This Interconnection Process uses the term DER to address all types of generation and energy resources that can be interconnected to the electric Distribution System. DER technologies can include photovoltaic solar systems, wind turbines, storage batteries or diesel generators and are not limited to renewable types of technologies.

1.2. Point of Common Coupling (PCC) / Point of DER Connection (PoC)

DER systems often reside behind the utility's revenue meter of a residence or business. The transformer or top of pole for overhead lines is normally the point of demarcation between the utility-owned equipment and the customer-owned equipment. The term Point of Common Coupling, PCC, is the demarcation location between the utility and the customer.

The Point of DER Connection, PoC, can be different from the PCC. The PoC is the location where a DER system would interconnect to the electrical system normally owned by the customer. For example, the PoC for a rooftop photovoltaic solar system may be the main electrical panel in a customer's home.

1.3. Capacity

Throughout the Interconnection Process will be references to the capacity of the DER system. In most cases, the capacity listed is referring to the Nameplate Capacity of the DER system. All capacity references will be in alternating current, AC.

There can be multiple DER systems with different PoCs that all have the same PCC submitted on a single interconnection application. The capacity for this type of interconnection would be the aggregate Nameplate Capacity of all DER systems at the individual PoCs. Additional examples of DER system arrangements can be seen in Section 13 under the definition of Point of Common Coupling.

2 Roles

2.1. Overview

During the interconnection process for a proposed DER system, there may be multiple entities involved in the application, approval and commissioning processes. The main entities that are involved during the Interconnection Process for a proposed DER system are the Interconnection Customer, the Application Agent and the DER Interconnection Coordinator. Official definitions of each entity are defined in the Glossary (Section 13). Additional details are explained in the subsections below.

2.2. DER Interconnection Coordinator

The utility is referred to as the Area Electric Power Supply Operator (Area EPS Operator) in this Interconnection Process. The Area EPS Operator shall designate a DER Interconnection Coordinator to serve as a single point of contact from which general information on the application process may be obtained. The DER Interconnection Coordinator shall be available to provide coordination assistance with the Interconnection Customer but is not responsible for directly answering or resolving all of the issues involved in review and implementation of the interconnection process and standards.

The contact information of the DER Interconnection Coordinator will be posted on the Area EPS Operator's website if feasible, or available from the utility.

2.3. Interconnection Customer

The owner of the proposed DER system and the entity requesting interconnection to the distribution system.

2.4. Application Agent

The Interconnection Customer may designate, on the Interconnection Application or in writing after the application has been submitted, an Application Agent to serve as a single point of contact to coordinate with the DER Interconnection Coordinator on their behalf. Designation of an Application Agent does not absolve the Interconnection Customer from signing application documents and the responsibilities outlined in the Interconnection Process or in interconnection agreements. DER vendors, project managers or electricians are common entities that the Interconnection Customer may designate to perform this role.

2.5. Engineering Roles

Either party may designate a specific person to be a single point of contact to provide technical expertise during the Interconnection Process for themselves or their organization. The person to supply engineering expertise may be a third party such as an engineering consultant or manufacturer's engineer.

3 Processes

3.1. Overview

The Interconnection Process applies to any DER no larger than 10 MW AC interconnecting to and operating in parallel with an Area EPS distribution system in Minnesota. Interested parties with plans to interconnect DER systems larger than 10 MW AC to the distribution system should contact the Area EPS Operator for a case-specific interconnection process. Federal Energy Regulatory Commission's (FERC) interconnection process will supersede any interconnection process the Area EPS Operator has for DER system interconnections that fall under the jurisdiction of FERC.

The Interconnection Process for DER is broken into three different tracks; the Simplified Process, the Fast Track Process, and the Study Process. The general classification of each track is summarized in Table 3.1 below.

Table 3.1. Interconnection Process Tracks

Track	DER Technology	Size Limitations
Simplified Process	Certified Inverter only	20 kW AC
Fast Track Process	All types	5 MW AC
Study Process	All types	10 MW AC

If engineering screens are failed during the application process, a proposed DER interconnection may be moved into a different track. When a proposed DER interconnection is moved into a different track, additional information may be requested and additional fees may apply.

3.2. Importance of Process Timelines

It is very important to pay attention to timelines listed for each process track. The timelines exist for an orderly and efficient process to interconnect DER systems to the Distribution System. If a timeline is missed by an Interconnection Customer, without the Interconnection Customer requesting a Timeline Extension explained in Section 10, the Interconnection Application will be deemed withdrawn by the Area EPS Operator.

The Area EPS Operator also needs to abide by the timelines listed for each process track. The process for an Area EPS Operator to request Timeline Extensions is also addressed in Section 10.

Unless otherwise stated, all time frames are measured in Business Days. For purpose of measuring these time intervals, the time shall be computed so as to exclude the first and include the last day of the prescribed duration of time. Any communication sent or received after 4:30 p.m. Central Prevailing Time or on a Saturday, Sunday or Holiday shall be considered to be sent on the next Business Day.

3.3. Simplified Process

An application to interconnect a certified[1], inverter-based DER system no larger than 20 kilowatts (kW) shall be evaluated under the Simplified Process. A common form of DER inverter certification is UL 1741. Proposed DER systems that require Area EPS system modifications to accommodate the interconnection do not qualify for the Simplified Process. A transformer change, fusing upgrades or line extensions are common examples of Area EPS system modification. Simplified Process eligibility does not imply or indicate the Interconnection Application will pass the initial review screens. Failure to pass the screens will route the Interconnection Application to the Fast Track Process.

3.4. Fast Track Process

An application to interconnect a DER shall be evaluated under the Fast Track Process if the eligibility requirements are not exceeded in Table 3.2 and the application does not qualify for the Simplified Process. Fast Track eligibility for DERs is determined based upon the generator type, the size of the generator, voltage of the line, and the location and type of line at the Point of Common Coupling, (PCC). All synchronous and induction machines must be no larger than 2 MW to be eligible for Fast Track Process consideration.

Table 3.2. Fast Track Eligibility for DER

Line Voltage	Fast Track Eligibility[2] Regardless of Location	Fast Track Eligibility for certified, inverter-based DER on a Mainline[3] and ≤ 2.5 Electrical Circuit Miles from Substation[4]
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 30 kV	≤ 2 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

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[1] Additional information regarding certified equipment is found in Sections 14 and 15.
[2] Synchronous and induction machine eligibility is limited to no more than 2 MW even when line voltage is greater than 15 kV.
[3] For purposes of this table, a Mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 266 kcmil, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.
[4] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report described in Section 5.

In addition to the size threshold, the Interconnection Customer’s proposed DER must meet the codes, standards and certification requirements found in Section 15 and Section 14.

3.5. Study Process

An application to interconnect a DER that does not meet the Simplified Process or Fast Track Process eligibility requirements or does not pass the review as described in either process, shall be evaluated under the Study Process.

3.6. Process Assistance

Prior to submitting an Interconnection Application, the Interconnection Customer may ask the Area EPS Operator’s DER Interconnection Coordinator which process track a proposed interconnection is subject to and about additional details regarding each process track.

An Interconnection Customer can obtain, through an informal request, general information about the Interconnection Process and about potentially Affected System(s) for a proposed interconnection at a specific location. The existing electric system information provided to the Interconnection Customer should include relevant system study results, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Area EPS Operator’s System. Information will be provided to the extent such provision does not violate the privacy policies of the Area EPS Operator, confidentiality provisions of prior agreements or critical infrastructure requirements. The Area EPS Operator shall comply with reasonable requests for such information.

4 Interconnection Application

4.1. Overview

Each process track has different information that needs to be provided to the Area EPS Operator. Table 4.1 indicates which application is to be completed in its entirety and submitted to the Area EPS Operator to start the interconnection process for the proposed DER system.

Table 4.1. Interconnection Application

Process Track	Application
Simplified	Simplified Interconnection Application
Fast Track	Standard Interconnection Application
Study	Standard Interconnection Application

The Area EPS Operator will provide all necessary Interconnection Applications, Interconnection Process documents and sample interconnection agreements on its website if possible. The Area EPS Operator will also accept Interconnection Applications submitted electronically to an email address specified by the Area EPS Operator. The Area EPS Operator may allow the Interconnection Application to be submitted with a certified electronic signature.

4.2. Availability of Information

The Area EPS Operator will provide all necessary Interconnection Applications, Interconnection Process documents and sample interconnection agreements on its website if possible. If a website is not available, the applicable documents will be readily available at the Area EPS Operator's main office.

The Area EPS Operator will establish a public queue of active interconnection applications on its website once the Area EPS Operator has received at least 40 completed Interconnection Applications in a year. The public queue will be updated, at minimum, on a monthly basis.

4.3. Interconnection Application Process Fees

Each Interconnection Application submitted to the Area EPS Operator must include the appropriate interconnection application process fee prior to the Area EPS Operator reviewing the Interconnection Application. The required process fee for each process track is listed in Table 4.2.

Table 4.2. Interconnection Application Process Fee

Process Track		Process Fee
Simplified		\$100
Fast Track	Certified[5] System	\$100 + \$1/kW
	Non-Certified System	\$100 + \$2/kW
Study		\$1,000 + \$2/kW down payment. Additional study fees may apply.

4.4. Application Review Timelines

The Interconnection Application shall be date- and time-stamped upon initial, and if necessary, resubmission receipt. The Area EPS Operator shall notify the Interconnection Customer if the Interconnection Application is deemed incomplete

[5] Additional information regarding certified equipment is found in Sections 14 and 15.

within ten (10) Business Days. This notification shall include a written list detailing all information that must be provided to complete the Interconnection Application. Depending on the process track the Interconnection Customer has between five (5) and ten (10) Business Days to provide the missing information unless additional time is requested with valid reasons. Failure to submit the requested information within the stated timeline will result in the Interconnection Application being withdrawn.

An Interconnection Application will be deemed complete upon submission to the Area EPS Operator when all documents, fees and information required with the Interconnection Application adhering to Minnesota Technical Requirements are included. The time- and date- stamp of the completed Interconnection Application shall be accepted as the qualifying date for purposes of establishing a queue position as described in Section 4.7.

Depending on the process track the Area EPS Operator has either a total of twenty (20) Business Days or twenty-five (25) Business Days to complete the Interconnection Application review and submit notice back to the Interconnection Customer stating the proposed DER system may proceed with the interconnection process or the proposed DER system requires additional engineering studies. The period of time when waiting for the Interconnection Customer to provide missing information is not included in the Area EPS Operator's twenty (20) Business Days or twenty-five (25) Business Days review timeline.

4.5. Comparability

The Area EPS Operator shall receive, process and analyze all Interconnection Applications in a timely manner. The Area EPS Operator shall use the same Reasonable Efforts in processing and analyzing Interconnection Applications from all Interconnection Customers.

4.6. Changing Process Queues

During the review of the initially submitted Interconnection Application for the proposed DER system, the Area EPS Operator may determine the proposed DER system should be in a different process track. For proposed DER systems that are moved into a different process track after submittal of the initial application, the difference between the originally submitted processing fee and the current process track's processing fee will be assessed. In addition, the Area EPS Operator may request the Interconnection Customer to provide additional information regarding the proposed DER system.

4.7. Queue Position

The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region. The queue position of each completed Interconnection Application is used to determine the engineering review. The queue position is also used to determine the cost responsibility for system upgrades necessary to accommodate the interconnection.

An Interconnection Application will retain its queue number even when it is moved into a different process track. An Interconnection Application can lose its queue position if the Interconnection Customer misses timelines in the applicable process track. The Interconnection Customer and Area EPS Operator have the opportunity to request timeline extensions which are explained in detail in Section 10.

4.8. Site Control

Documentation of site control must be submitted with the Interconnection Application. Site control may be demonstrated by any of the following:

- Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the DER system.
- An option to purchase or acquire a leasehold site for constructing the DER system.
- An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant to the Interconnection Customer the right to possess or occupy a site for constructing the DER system.

For DER in the Simplified Process, proof of site control may be demonstrated by the site owner’s signature on the Simplified Interconnection Application.

5 Pre-Application Report

5.1. Pre-Application Report Requests

The Interconnection Customer may submit a Pre-Application Report Request, including a non-refundable fee of $300, for a Pre-Application Report on a proposed project at a specific site. The Interconnection Customer must fill out the Pre-Application Request form as completely as possible. The Area EPS Operator shall provide the readily available data listed in Section 5.3 within fifteen (15) Business Days of receipt of a completed request form and payment. The Pre-Application Report produced by the Area EPS Operator is non-binding, does not confer any rights, and does not preclude the Interconnection Customer from any interconnection process steps including submission of the Interconnection Application.

5.2. Information Provided

Using the information provided in the Pre-Application Report Request form, the Area EPS Operator will identify the substation/area bus, bank or circuit likely to serve the proposed PCC. This selection by the Area EPS Operator does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional Pre-Application Reports if information about multiple PCCs is requested.

The Pre-Application Report will only include existing data. A request for a Pre-Application Report does not obligate the Area EPS Operator to conduct a study or other analysis of the proposed DER in the event that data is not readily available. The Area EPS Operator will provide the Interconnection Customer with the data that is available. The confidentiality provisions in Section 12.1 apply to Pre-Application Reports.

5.3. Pre-Application Report Components

The Pre-Application Report shall include the following pieces of information provided the data currently exists and is readily available.

- Total capacity (in megawatts (MW)) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Common Coupling.

- Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Common Coupling.

- Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Common Coupling.

- Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Common Coupling (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

- Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

- Nominal distribution circuit voltage at the proposed Point of Common Coupling.

- Approximate circuit distance between the proposed Point of Common Coupling and the substation.

- Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load and absolute minimum load, when available.

- Whether the Point of Common Coupling is located behind a line voltage regulator.

- Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.

- Number of phases available on the Area EPS medium voltage system at the proposed Point of Common Coupling. If a single phase, distance from the three-phase circuit.

- Limiting conductor ratings from the proposed Point of Common Coupling to the distribution substation.

- Whether the Point of Common Coupling is located on a spot network, grid network, or radial supply.

- Based on the proposed Point of Common Coupling, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

6 Capacity of the Distributed Energy Resources

6.1. Existing DER System Expansion

If the Interconnection Application is for an increase in capacity to an existing DER system, the Interconnection Application shall be evaluated on the basis of the total new alternating current (AC) capacity of the DER. The maximum capacity for the DER shall be the aggregate maximum Nameplate Rating unless the conditions in Section 6.3 are met.

6.2. New DER Systems

An Interconnection Application for a DER that includes multiple energy production devices, (i.e. solar and storage), at a site for which the Interconnection Customer seeks a simple Point of Common Coupling, shall be evaluated on the basis of the aggregated maximum Nameplate Rating unless the conditions in Section 6.3 are met.

6.3. Limited Capacity

A DER system may include devices, (i.e. control systems, power relays or other similar device settings), that can limit the maximum capacity at which the DER system can generate into the Area EPS Operator's distribution system. For DER system that include capacity limited devices, the Interconnection Customer must obtain the Area EPS Operator's agreement to consider the DER system with the Nameplate Rating as the limited capacity. The Area EPS Operator's agreement shall not be unreasonably withheld provided proper documentation is provided showing the effective limit active power output will not adversely affect the safety and reliability of the Area EPS Operator's distribution system. If the Area EPS Operator does not agree, the Interconnection Application must be withdrawn or revised to specify the maximum capacity that the DER system is capable of injecting into the Area EPS Operator's distribution system without such limitations. Nothing in this section shall prevent the Area EPS Operator from considering a higher output, (i.e. aggregate Nameplate Rating), if the limitations do not provide adequate assurance, when evaluating the system impacts.

7 Modification to Interconnection Applications

7.1. Procedures

At any time after the Interconnection Application is deemed complete, the Interconnection Customer or the Area EPS Operator may identify modifications to the proposed DER system that may improve costs and benefits (including reliability) of the proposed DER system and the ability for the Area EPS Operator to accommodate the proposed DER system. The Interconnection Customer shall submit to the Area EPS Operator in writing all proposed modifications to any information provided in the Interconnection Application. The Area EPS Operator cannot unilaterally modify the Interconnection Application.

Additional information regarding modifications to interconnection applications is found in each process track document.

8 Interconnection Agreements

8.1. Timelines

After the Interconnection Application has been approved by the Area EPS Operator, the Area EPS Operator shall provide the Interconnection Customer with an executable Interconnection Agreement within five (5) Business Days. The Interconnection

Customer shall have thirty (30) Business Days to sign and return the Interconnection Agreement to the Area EPS Operator. The Area EPS Operator shall sign the Interconnection Agreement within five (5) business days after receiving the signed Interconnection Agreement from the Interconnection Customer.

If the Interconnection Customer fails to return a signed Interconnection Agreement to the Area EPS Operator within thirty (30) Business Days and fails to request an extension as explained in Section 10, the Interconnection Application will be deemed withdrawn.

8.2. Types of Agreements

There are two main types of Interconnection Agreements that may be executed with an approved Interconnection Application. In general, Interconnection Customers with a proposed DER system that qualifies for the Simplified Process track will sign the Area EPS Operator's Uniform Contract for Cogeneration and Small Power Production Facilities (Uniform Contract). Proposed DER systems less than 40 kW that are under the Fast Track process may also sign the Uniform Contract. All other sized DER system will sign the Municipal Minnesota Interconnection Agreement (MMIA) in conjunction with the Minnesota Municipal Power Agency Distributed Generation Tariff. Area EPS Operators who do not purchase the excess generation of the proposed DER system will also require the MMIA to be executed for any size of DER system.

Table 8.1. Interconnection Agreements

<table>
<tr><th colspan="2">Process Track</th><th>Interconnection Agreement</th></tr>
<tr><td colspan="2">Simplified</td><td>Uniform Contract</td></tr>
<tr><td rowspan="3">Fast Track</td><td>Qualifies for Net Energy Billing</td><td>Uniform Contract</td></tr>
<tr><td>Less than 100 kW & Area EPS Agrees to Purchase Excess Generation</td><td>Uniform Contract</td></tr>
<tr><td>All Other DER systems</td><td>MMIA</td></tr>
<tr><td colspan="2">Study</td><td>MMIA</td></tr>
</table>

Interconnection Customers may choose to sign the MMIA in lieu of the Uniform Contract. A separate power purchase agreement will also need to be executed if the Uniform Contract is not utilized. Interconnection of the proposed DER system will not occur until a signed Uniform Contract or the MMIA is returned to the Area EPS Operator no later than five (5) days prior to scheduled testing and inspection.

9 Interconnection

9.1. Metering

Any metering requirements necessitated by the use of the DER system shall be installed at the Interconnection Customer's expense. The metering requirement costs will be included in the final invoice of interconnection costs to the Interconnection Customer. The Interconnection Customer is also responsible for metering replacement costs not covered in the Interconnection Customer's general customer charge. The Area EPS Operator may charge Interconnection Customers an ongoing metering-related charge for an estimate of ongoing metering-related costs specifically demonstrated.

9.2. Inspection, Testing and Commissioning

The Interconnection Customer shall arrange for the inspection and testing of the DER system and the Customer's Interconnection Facilities prior to interconnection pursuant to Minnesota Technical Requirements. Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards of Minnesota's Technical Requirements and Section 15.

The Interconnection Customer shall notify the Area EPS Operator of testing and inspection no fewer than five (5) Business Days in advance, or as may be agreed to by the Parties. Depending on the process track, either a Certificate of Completion or a testing procedure shall be submitted to the Area EPS Operator prior to the testing and inspection date. The Area EPS Operator shall send qualified personnel to the DER site to inspect the interconnection and witness the testing. Testing and inspection shall occur on a Business Day at a mutually agreed upon time and date. The Area EPS Operator may waive the right to witness the testing.

9.3. Interconnection Costs

The Interconnection Customer shall pay for the actual cost of the Interconnection Facilities and Distribution Upgrades along with the Area EPS Operator's cost to commission the proposed DER system. An estimate of the interconnection costs shall be stated in the Uniform Contract or MMIA.

9.4. Technical Requirements

The Area EPS Operator shall use Reasonable Efforts to provide the Interconnection Customer the Minnesota Technical Requirements by providing the document with the notice of approval of the interconnection application or by providing a website link to the document. Additionally, the Area EPS Operator shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. Unless notified by the Area EPS Operator, the Interconnection Customer only needs to be in compliance with the current version of the Minnesota Technical Requirements at the time of interconnection.

9.5. Authorization for Parallel Operations

The Interconnection Customer shall not operate its DER system in parallel with the Area EPS Operator’s distribution system without prior written authorization from the Area EPS Operator. The Area EPS Operator shall provide such authorization within three (3) Business Days from when the Area EPS Operator receives notification that the Interconnection Customer has complied with all applicable parallel operations requirements; the completion of a successful testing and inspection of the DER system and all payments for issued bills related to the interconnection process that are past due have been paid in full. Such authorization shall not be unreasonably withheld, conditioned or delayed.

10 Extension of Timelines

10.1. Reasonable Efforts

The Area EPS Operator shall make Reasonable Efforts to meet all time frames provided in these procedures. If the Area EPS Operator cannot meet a deadline provided herein, it must notify the Interconnection Customer in writing within three (3) Business Days after the deadline to explain the reason for the failure to meet the deadline and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

10.2. Extensions

For applicable time frames described in these procedures, the Interconnection Customer may request, in writing, one extension equivalent to half of the time originally allotted (e.g., ten (10) Business Days for a twenty (20) Business Days original time frame) which the Area EPS Operator may not unreasonably refuse. No further extensions for the applicable time frame shall be granted absent a Force Majeure Event or other similarly extraordinary circumstance.

11 Disputes

11.1. Procedures

The Parties agree to make good faith efforts to attempt to resolve all disputes arising out of the interconnection process and associated study and Interconnection Agreements. The Parties agree to follow the established dispute resolution policy adopted by the Area EPS Operator.

12 Clauses

12.1. Confidentiality

Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such. If requested by either Party, the other Party shall provide in writing the basis for asserting that the information warrants confidential treatment. Parties providing a Governmental Authority trade secret, or privileged or otherwise not public or nonpublic data under Minnesota Government Data Practices Act, Minnesota Statutes Chapter 13, shall identify such data consistent with the Commission's September 1, 1999 Revised Procedures for Handling Trade Secret and Privileged Data available online at: https://mn.gov/puc/puc-documents/#4.

Confidential Information does not include information previously in the public domain with proper authorization, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be publicly divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements that could not otherwise be fulfilled by not making the information public.

Each Party shall hold in confidence and shall not disclose Confidential Information, to any person (except employees, officers, representatives and agents, who agree to be bound by this section). Confidential Information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency or entity with the right, power, and authority to do so, requests or requires either Party, by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver the Party shall disclose such confidential information which, in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded to any confidential information furnished.

Critical infrastructure information or information that is deemed or otherwise designated by a Party as Critical Energy/Electric Infrastructure Information (CEII) pursuant to FERC regulation, 18 C.F.R. §388.133, as may be amended from time to time, may be subject to further protections for disclosure as required by FERC or FERC regulations or orders and the disclosing Party's CEII policies. Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages and may seek other remedies available at law or in equity for breach of this provision.

12.2. Non-Warranty

The Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, operated, installed or maintained by the Interconnection Customer, including without limitation the DER and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator. The Area EPS Operator does not guarantee uninterrupted power supply to the DER and will operate the Distribution System with the same reliability standards for the entire customer base.

12.3. Indemnification

Each Party is protected from liability incurred to third parties as a result of carrying out the provisions of this interconnection process and subsequent interconnection agreements. The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

This indemnification obligation shall apply notwithstanding any negligent or intentional acts, errors or omissions of the indemnified Party, but the indemnifying Party's liability to indemnify the indemnified Party shall be reduced in proportion to the percentage by which the indemnified Party's negligent or intentional acts, errors or omissions caused the damages.

Neither Party shall be indemnified for its damages resulting from its sole negligence, intentional acts or willful misconduct. These indemnity provisions shall not be construed to relieve any insurer of its obligation to pay claims consistent with the provisions of a valid insurance policy.

If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

12.4. Limitation of Liability

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for an indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under in Section 12.3.

13 Glossary

Affected System – Another Area EPS Operator's System, Transmission Owner's Transmission System, or Transmission System connected generation which may be affected by the proposed interconnection.

Applicant Agent – A person designated in writing by the Interconnection Customer to represent or provide information to the Area EPS on the Interconnection Customer's behalf throughout the interconnection process.

Area EPS – The electric power distribution system connected at the Point of Common Coupling.

Area EPS Operator – An entity that owns, controls, or operates the electric power distribution systems that are used for the provision of electric service in Minnesota. For this Interconnection Process the Area EPS Operator is The City of Olivia Municipal Utilities.

Business Day – Monday through Friday, excluding Holidays as defined by Minn. Stat. §645.44, Subdivision 5. Any communication to have been sent or received after 4:30 p.m. Central Prevailing Time or on a Saturday, Sunday or holiday shall be considered to have been sent on the next Business Day.

Certified Equipment – Certified equipment is equipment that has been tested by a nationally recognized lab meeting a specific standard. For DER systems, a UL 1741 listing is a common form of DER inverter certification. Additional information is contained in Sections 14 and 15.

Confidential Information – Any confidential and/or proprietary information provided by one Party to the other Party and is clearly marked or otherwise designated "Confidential." All procedures, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information. See Section 12.1 for further information.

Distributed Energy Resource (DER) – A source of electric power that is not directly connected to a bulk power system or central station service. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER. For the purpose of the Interconnection Process and interconnection agreements, the DER includes the Customer's Interconnection Facilities but shall not include the Area EPS Operator's Interconnection Facilities.

Distribution System – The Area EPS facilities which are not part of the Local EPS, Transmission System or any generation system.

Distribution Upgrades – The additions, modifications, and upgrades to the Distribution System at or beyond the Point of Common Coupling to facilitate interconnection of the DER and render the distribution service necessary to effect the Interconnection Customer's connection to the Distribution System. Distribution Upgrades do not include Interconnection Facilities.

Electric Power System (EPS) – The facilities that deliver electric power to a load.

Fast Track Process – The procedure as described in the Interconnection Process - Fast Track Process for evaluating an Interconnection Application for a DER that meets the eligibility requirements of Section 3.4.

Force Majeure Event – An act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, an order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or another cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Area EPS Operator, or any Affiliate thereof. The governing authority of the municipal utility is the authority governing interconnection requirements unless otherwise provided for in the Minnesota Technical Requirements.

Interconnection Agreement – The terms and conditions between the Area EPS Operator and Interconnection Customer (Parties). See Section 8 for when the Uniform Contract or Municipal Minnesota Interconnection Agreement applies.

Interconnection Application – The Standard or Simplified Interconnection Application, as applicable, pursuant to Section 4.

Interconnection Customer – The person or entity, including the Area EPS Operator, who will be the owner of the DER and who proposes to interconnect a DER(s) with the Area EPS Operator's Distribution System. The Interconnection Customer is responsible for ensuring the DER(s) is designed, operated and maintained in compliance with the Minnesota Technical Requirements.

Interconnection Facilities – The Area EPS Operator's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the DER and the Point of Common Coupling, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the DER to the Area EPS Operator's System. Some examples of Customer Interconnection Facilities include supplemental DER devices, inverters, and associated wiring and cables up to the Point of DER Connection. Some examples of Area EPS Operator Interconnection Facilities include sole use facilities; such as, line extensions, controls, relays, switches, breakers, transformers and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Process – The Area EPS Operator's interconnection standards in this document.

Material Modification – A modification to machine data, equipment configuration or to the interconnection site of the DER at any time after receiving notification by the Area EPS Operator of a complete Interconnection Application that has a material impact on the cost, timing, or design of any Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later Queue Position or the safety or reliability of the Area EPS.[6]

MN Technical Requirements – The term including all of the DER technical interconnection requirement documents for the state of Minnesota; including Attachment 2 Distributed Generation Interconnection Requirements established in the Commission's September 28, 2004 Order in E-999/CI-01-1023) until superseded and upon Commission approval of updated Minnesota DER Technical Interconnection and Interoperability Requirements in E-999/CI-16-521 (anticipated July 2019.)

Nameplate Rating – nominal voltage (V), current (A), maximum active power (kWac), apparent power (kVA), and reactive power (kVar) at which a DER is capable of sustained operation. For a Local EPS with multiple DER units, the aggregate nameplate rating is equal to the sum of all DERs nameplate rating in the Local EPS. For purposes of the Attachment V in the Interconnection Agreement, the DER system's capacity may, with the Area EPS's agreement, be limited through use of control systems, power relays or similar device settings or adjustments as identified in IEEE 1547. The nameplate ratings referenced in the Interconnection Process are alternating current nameplate DER ratings at the Point of DER Coupling.

Network Upgrades – Additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the DER interconnects with the Area EPS Operator's System to accommodate the interconnection with the DER to the Area EPS Operator's System. Network Upgrades do not include Distribution Upgrades.

[6] A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) changes the physical location of the point of common coupling such that it is likely to have an impact on technical review; (2) increases the nameplate rating or output characteristics of the Distributed Energy Resource; (3) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (4) changes transformer connection(s) or grounding; and/or (5) changes to a certified inverter with different specifications or different inverter control settings or configuration. A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes the ownership of a Distributed Energy Resource; (2) changes the address of the Distributed Energy Resource, so long as the physical point of common coupling remains the same; (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; and/or (4) increases the DC/AC ratio but does not increase the maximum AC output capability of the Distributed Energy Resource in a way that is likely to have an impact on technical review.

Operating Requirements – Any operating and technical requirements that may be applicable due to the Transmission Provider's technical requirements or Minnesota Technical Requirements, including those set forth in the Interconnection Agreement.

Party or Parties – The Area EPS Operator and the Interconnection Customer.

Point of Common Coupling (PCC) – The point where the Interconnection Facilities connect with the Area EPS Operator's Distribution System. See figure 1. Equivalent, in most cases, to "service point" as specified by the Area EPS Operator and described in the National Electrical Code and the National Electrical Safety Code.

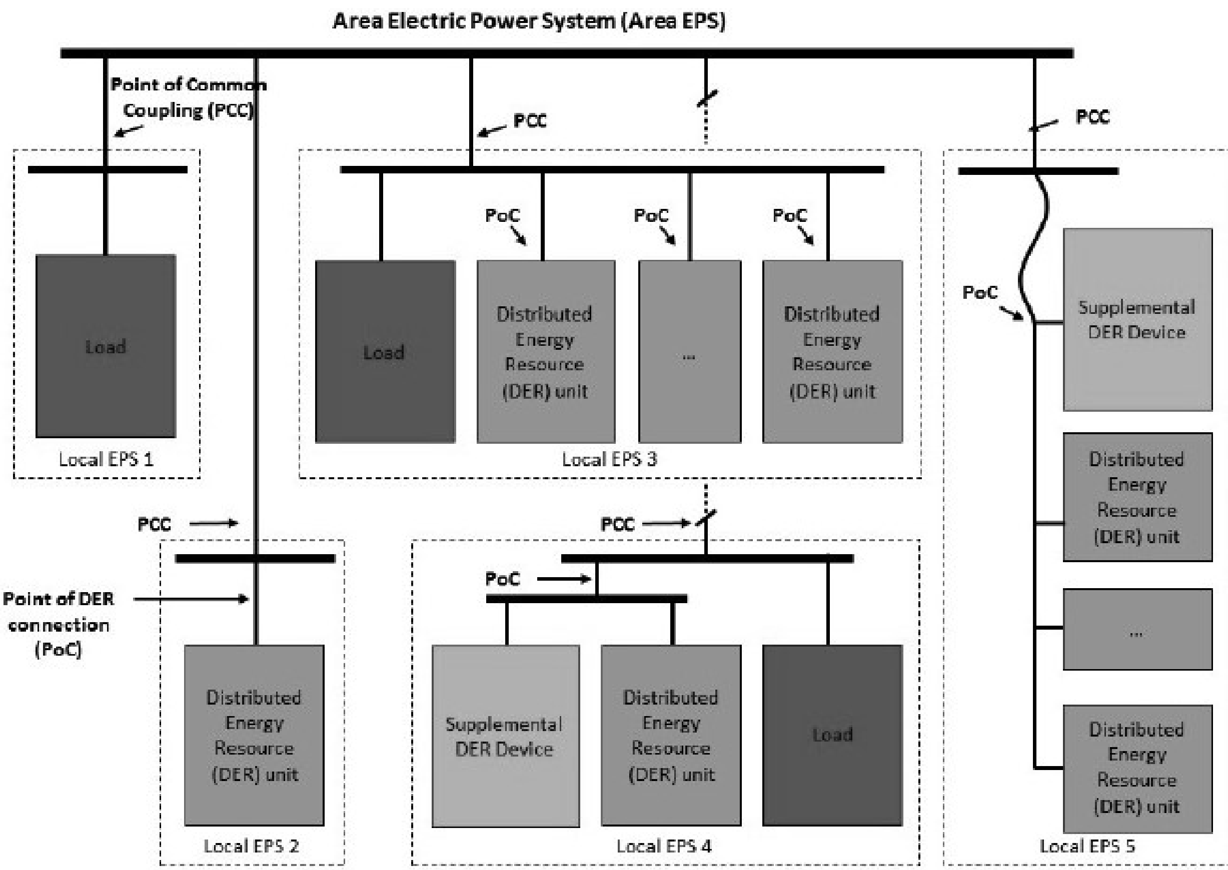


Figure 1: Point of Common Coupling and Point of DER Connection (Source: IEEE 1547)

Point of DER Connection (PoC) – When identified as the Reference Point of Applicability, the point where an individual DER is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS (e.g. terminals of the inverter when no supplemental DER device is required). For DER unit(s) that are not self-sufficient to meet the requirements without a supplemental DER device(s), the Point of DER Connection is the point where the requirements of this standard are met by DER in conjunction with a supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

Queue Position – The order of a valid Interconnection Application, relative to all other pending valid Interconnection Applications, that is established based upon the date- and time- of receipt of the complete Interconnection Application as described in Section 4.7.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under these procedures, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Reference Point of Applicability – The location, either the Point of Common Coupling or the Point of DER Connection, where the interconnection and interoperability performance requirements specified in IEEE 1547 apply. With mutual agreement, the Area EPS Operator and Customer may determine a point between the Point of Common Coupling and Point of DER Connection. See Minnesota Technical Requirements for more information.

Simplified Process – The procedure for evaluating an Interconnection Application for a certified inverter-based DER no larger than 20 kW that uses the screens described in the Interconnection Process – Simplified Process document. The Simplified Process includes simplified procedures.

Study Process – The procedure for evaluating an Interconnection Application that includes the scoping meeting, system impact study, and facilities study.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System relevant to the Interconnection.

Transmission Provider – The entity (or its designated agent) that owns, leases, controls, or operates transmission facilities used for the transmission of electricity. The term Transmission Provider includes the Transmission Owner when the Transmission Owner is separate from the Transmission Provider. The Transmission Provider may include the Independent System Operator or Regional Transmission Operator.

Transmission System – The facilities owned, leased, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service. See the Commission's July 26, 2000 Order Adopting Boundary Guidelines for Distinguishing Transmission from Generation and Distribution Assets in Docket No. E-999/CI-99-1261.

Uniform Contract – the Area EPS Operator's Agreement for Cogeneration and Small Power Production Facilities (Uniform Contract) that may be applied to all qualifying new and existing interconnections between the Area EPS Operator and a DER system having capacity less than 40 kilowatts.

Upgrades – The required additions and modifications to the Area EPS Operator's Transmission or Distribution System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

14 Certification of DER Equipment

Distributed Energy Resource (DER) equipment proposed for use in an interconnection system shall be considered certified for interconnected operation if the following criteria is met:

1) It has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in the Overview Process,

2) It has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and

3) Such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

The Interconnection Customer must verify that the assembly and use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for a DER Design Evaluation or an on-site commissioning test by the parties to the interconnection as provided for in the Minnesota Technical Requirements.

If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL and does not violate the interface components' labeling and listing performed by the NRTL, no further type-test review, testing or additional equipment on the customer side of the Point of Common Coupling shall be required to be considered certified for the purposes of this interconnection procedure; however, nothing herein shall preclude the need for a DER design evaluation or an on-site commissioning test by the parties to the interconnection as provided for in the Minnesota Technical Requirements.

An equipment package does not include equipment provided by the Area EPS.

15 Certification Codes and Standards

The existing Minnesota Technical Requirements and the following standards shall be used in conjunction with the Interconnection Process. The process has started to update the Technical Requirements to meet IEEE 1547-2018. Once that process is completed, the updated DER Technical Interconnection and Interoperability Requirements will supersede this section.

When the stated version of the following standards is superseded by an approved revision then that revision shall apply:

IEEE 1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547a-2014 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1

IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547.1a-2015 (Amendment to IEEE Std 1547.1-2005) IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems – Amendment 1

UL 1741 Inverters, Converters, Controllers, and Interconnection System Equipment for Use in Distributed Energy Resources (2010)

NFPA 70 (2017), National Electrical Code

IEEE Std C37.90.1 (2012) (Revision of IEEE Std C37.90.1-2002), IEEE Standard for Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems Associated with Electric Power Apparatus

IEEE Std C37.90.2 (2004) (Revision of IEEE Std C37.90.2-1995), IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-20021989 (Revision of C37.108-19892002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2014 (Revision of IEEE Std C57.12.44-2005), IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits

IEEE Std C62.41.2-2002_Cor 1-2012 (Corrigendum to IEEE Std C62.41.2-2002) – IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits Corrigendum 1: Deletion of Table A.2 and Associated Text

IEEE Std C62.45-2002 (Revision of IEEE Std C62.45-1992) – IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and less) AC Power Circuits

ANSI C84.1-(2016) Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Standards Dictionary Online, [Online]

NEMA MG 1-2016, Motors and Generators

IEEE Std 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

St. Cloud Utility's 220 kW Wastewater Solar Array
St. Cloud, MN

INTERCONNECTION PROCESS

Fast Track Process

ABSTRACT

Information in addition to the "Process Overview" for interconnecting Distributed Energy Resources smaller than 4 megawatts in size that do not qualify for the "Simplified Process."

Contents

1 Applicability

1.1. Capacity Limit

The Fast Track Process is available to an Interconnection Customer proposing to interconnect a Distributed Energy Resource (DER) with the Area EPS Operator's Distribution System if the DER capacity does not exceed the size limits in Table 1.1 and does not qualify for the Simplified Process. The capacity is determined by the aggregated summation of the Nameplate Rating of all components that make up the DER system. Additional information regarding the capacity limits can be seen in Section 6 of the Process Overview document.

Table 1.1. Fast Track Eligibility for DER

Line Voltage	Fast Track Eligibility[1] Regardless of Location	Fast Track Eligibility for certified, inverter-based DER on a Mainline[2] and ≤ 2.5 Electrical Circuit Miles from Substation[3]
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

Fast Track eligibility for DERs is determined based upon the generator type, the size of the generator, voltage of the line, and the location of and the type of line at the Point of Common Coupling. All synchronous and induction machines must be no larger than 2 MW to be eligible for Fast Track Process consideration. Fast Track eligibility does not imply or indicate that a DER will pass the engineering screens or be exempt from the proposed DER Interconnection being placed into the Study Process.

1.2. Codes, Standards and Certification Requirements

The Interconnection Customer's proposed DER must meet the codes, standards and certification requirements listed in Section 14 and Section 15 of the Overview Process document. The Area EPS Operator may allow DER systems that do not meet codes, standards and certification only if the DER system design is reviewed and tested and determined that it is safe to operate in parallel with the Distribution System.

[1] Synchronous and induction machine eligibility is limited to no more than 2 MW even when line voltage is greater than 15 kV.

[2] For purposes of this table, a Mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 266 kcmil, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[3] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report described in the Overview Process document.

2 Application Submission

2.1. Fast Track Process Application

The Interconnection Customer shall complete the Standard Interconnection Application and submit it to the Area EPS Operator to initialize the Interconnection Process. A completed Interconnection Application will include the following:

- A completed Interconnection Application signed by the Interconnection Customer.
- A non-refundable processing fee indicated in Section 2.3.
- A site layout drawing of the proposed DER system.
- A one-line diagram of the proposed DER system showing the point of common coupling to the Area EPS Operator's Distribution System.
- All equipment manufacturer specification sheets.
- Documentation of site control indicated in Section 2.5.

2.2. Professional Licensed Engineer Signature

The one-line diagram submitted with the Interconnection Application will require a signature from a professional engineer licensed in the State of Minnesota certifying the DER was designed in conformance to the Minnesota Technical Requirements for the following conditions:

- Certified[4] equipment is greater than 250 kW.
- Non-certified equipment is greater than 20 kW.

2.3. Processing Fee

The processing fee will differ for a Fast Track Interconnection Application depending on the type of equipment utilized as seen in Table 2.1.

[4] Additional information regarding certified equipment is found in Section 14 and Section 15 of the Process Overview document.

Table 2.1. Interconnection Application Process Fee

Equipment Type	Process Fee
Certified System	$100 + $1/kW
Non-Certified System	$100 + $2/kW

2.4. Battery Storage

An inverter-based DER system may include battery storage. DER systems that include battery storage should complete the Energy Storage Application along with the Interconnection Application.

2.5. Site Control

Documentation of site control must be submitted with the Interconnection Application. Site control may be demonstrated by any of the following:

- Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the DER system.
- An option to purchase or acquire a leasehold site for constructing the DER system.
- An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for constructing the DER system.

3 Application Review

3.1. Timelines

The Interconnection Application shall be date- and time-stamped upon initial, and if necessary, resubmission receipt. The Interconnection Customer shall be notified of receipt by the Area EPS Operator within ten (10) Business Days of receipt of the Interconnection Application.

The Area EPS Operator shall notify the Interconnection Customer if the Interconnection Application is deemed incomplete within ten (10) Business Days and provide a written list detailing all information that must be provided to complete the Interconnection Application. The Interconnection Customer has ten (10) Business Days to provide the missing information unless additional time is requested with valid reasons. Failure to submit the requested information within the stated timeline will result in the Interconnection Application being deemed withdrawn. The Area EPS Operator has an additional five (5) Business Days to review the additionally provided information for completeness.

An Interconnection Application will be deemed complete upon submission to the Area EPS Operator provided all documents, fees and information required with the Interconnection Application adhering to Minnesota Technical Requirements is included. The time- and date- stamp of the completed Interconnection Application shall be accepted as the qualifying date for the purpose of establishing a queue position as described in Section 4.7 in the Overview Process document.

The Area EPS Operator has a total of twenty-five (25) Business Days to complete the Interconnection Application review and submit notice back to the Interconnection Customer stating the proposed DER system may proceed with the interconnection process or a supplemental review offer is to be made or the proposed DER system has been moved into a different process track. The period of time when waiting for the Interconnection Customer to provide missing information is not included in the Area EPS Operator's twenty-five (25) Business Days review timeline.

3.2. Initial Review Screens

The Area EPS Operator shall determine if the DER can be interconnected safely and reliably without the construction of facilities by the Area EPS Operator by using a set of Initial Review Screens. The Initial Review screens include the following engineering screens:

- The proposed DER's Point of Common Coupling must be on a portion of the Area EPS Operator's Distribution System.

- For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured or 100% of the substation aggregated minimum load. A line section is that portion of an Area EPS Operator's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. The Area EPS Operator may consider 100% of applicable loading (i.e. daytime minimum load for solar), if available, instead of 15% of line section peak load.

- For interconnection of a proposed DER to the load side of network protectors, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DERs, shall not exceed the smaller of 5% of a network's maximum load or 50 kW.[5]

- The proposed DER, in aggregation with other DERs on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed Point of Common Coupling.

- The proposed DER, in aggregate with other Distributed Energy Resources on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

- Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Area EPS Operator's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Table 3.1. Type of Primary Distribution Line Interconnections

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Results
Three-Phase, three wire	Three-phase or single-phase, phase-to-phase	Pass Screen
Three-phase, four wire	Effectively-grounded three-phase or single-phase, line-to-neutral	Pass Screen

- If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER, shall not exceed 20 kW or 65% of the transformer nameplate rating.

[5] Network protectors are protective devices used on secondary networks (spot and grid networks) to automatically disconnect associated transformers when reverse power flow occurs. Secondary networks are most often used in densely populated downtown areas.

- If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240-volt service, its addition shall not create an imbalance between the two sides of the 240-volt service of more than 20% of the nameplate rating of the service transformer.

The technical screens listed shall not preclude the Area EPS Operator from using tools that perform screening functions using different methodologies provided the analysis is targeted to maintain the voltage, thermal and protection objectives as the listed screen.

3.3. Notification of Approval of Application

Provided the Interconnection Application passes the initial screens, or if the proposed interconnection fails the screens but the Area EPS Operator determines that the DER may nevertheless be interconnected consistent with safety, reliability and power quality standards, the Area EPS Operator shall provide notice to the Interconnection Customer that their Interconnection Application has been approved. The Area EPS Operator shall provide the Interconnection Customer with an Interconnection Agreement as outlined in Section 5.

3.4. Failure of Review Screens

If the proposed interconnection fails the screens, and the Area EPS Operator does not or cannot determine from the Initial Review that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards, unless the Interconnection Customer is willing to consider minor modifications or further study, the Area EPS Operator shall provide the Interconnection Customer the opportunity to attend a customer options meeting.

The Area EPS Operator shall notify the Interconnection Customer of the determination and provide copies of all directly pertinent data and analyses underlying its conclusion, subject to confidentiality provisions in Section 12.1 of the Overview Process document.

3.5. Customer Options Meeting

Within ten (10) Business Days of the Area EPS Operator’s notification to the Interconnection Customer of the proposed interconnection’s failure of the engineering screens, the Area EPS Operator and the Interconnection Customer shall schedule a customer options meeting to review possible facility modification, screen analysis and related results to determine what further steps are needed to permit the DER to be interconnected safely and reliably to the Distribution System. At the customer options meeting the Area EPS Operator shall:

- Offer to perform a supplemental review in accordance with Section 4 and provide a non-binding good faith estimate of the cost of such review; or

- Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Application under the Study Process track.

4 Supplemental Review

4.1. Acceptance of Supplemental Review

To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit for the estimated costs of the supplemental review in the amount of the Area EPS Operator's good faith estimate of the costs of such review within fifteen (15) Business Days once the supplemental review offer is made by the Area EPS Operator. If the written agreement and deposit have not been received by the Area EPS Operator within that timeframe, the Interconnection Application can only continue being evaluated under the Study Process or it can be withdrawn by the Interconnection Customer.

The Interconnection Customer may specify within the written agreement the order in which the Area EPS Operator will complete the supplemental review screens listed in Section 4.4.

4.2. Supplemental Review Costs

The Interconnection Customer shall be responsible for the Area EPS Operator's actual costs for conducting the supplemental review. The Interconnection Customer shall pay any review costs that exceed the deposit within twenty (20) Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Area EPS Operator will return such excess within twenty (20) Business Days of the invoice without interest.

4.3. Supplemental Review Timelines

Within thirty (30) Business Days following the receipt of the deposit for a supplemental review, the Area EPS Operator shall:

- Perform the supplemental review using the screens in Section 4.4.

- Notify the Interconnection Customer of the results in writing.

- Include copies of the Area EPS Operator's analysis under the screens with the written notification.

Unless the Interconnection Customer provides instruction for how to respond to a failure of any of the supplemental review screens in the written acceptance of supplemental review, the Area EPS Operator shall notify the Interconnection Customer within two (2) Business Days if a supplemental review screen is failed or if the Area EPS Operator is unable to perform the supplemental review screen. The Area EPS Operator shall then obtain the Interconnection Customer's permission to either:

- Continue evaluating the proposed interconnection using the supplemental review screens in Section 4.4.
- Terminate the supplemental review and continue evaluating the Interconnection Application in the Study Process track.
- Terminate the supplemental review upon withdrawal of the Interconnection Application by the Interconnection Customer.

The Interconnection Customer shall respond with its choice within five (5) Business Days of notification from the Area EPS Operator.

4.4. Supplemental Review Screens

The three supplemental review screens are the Minimum Load screen, the Voltage and Power Quality screen and the Safety and Reliability screen.

4.4.1. Minimum Load Screen

The aggregate DER capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data is not available, or cannot be calculated, estimated or determined, the Area EPS Operator shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under Section 4.3. The line section minimum load data shall include onsite load but not station service load served by the proposed DER in this screen.

The type of generation used by the proposed DER will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for the application of this screen. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

When this screen is being applied to a DER that serves some station service load, only the net injection into the Area EPS Operator's electric system will be considered as part of the aggregate generation.

The Area EPS Operator will not consider as part of the aggregate generation for purposes of this screen DER capacity known to be already reflected in the minimum load data.

4.4.2. Voltage and Power Quality Screen

In aggregate with existing generation on the line section the following conditions shall be met for the screen to be passed:

- The voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions.

- The voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453.

- The harmonic levels meet IEEE Standard 519 limits.

4.4.3. Safety and Reliability Screen

The location of the proposed DER and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The Area EPS Operator shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

- Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

- Whether the loading along the line section is uniform or even.

- Whether the proposed DER is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Common Coupling is a main line rated for normal and emergency ampacity.

- Whether the proposed DER incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

- Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section(s) of the DER to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

- Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

4.5. Identification of Construction of Facilities

If the proposed interconnection requires the construction of any distribution or transmission facilities, the Area EPS Operator shall notify the Interconnection Customer of the requirement when it provides the supplemental review results. The Area EPS Operator may include a non-binding good faith estimate to construct the facilities included with the supplemental review results. In lieu of providing a non-binding good faith estimate to construct the necessary facilities, the Area EPS Operator may require the proposed interconnection to move to the Study Process for a facility study instead.

Upon being presented with either the non-binding good faith estimate or the requirement for a facility study, the Interconnection Customer has five (5) Business Days to inform the Area EPS Operator to proceed with the proposed interconnection or withdraw the Interconnection Application.

4.6. Supplemental Review Results

If the proposed interconnection passes the supplemental review screens in Section 4.4 and does not require construction of distribution or transmission facilities by the Area EPS on its own system, the Area EPS Operator shall provide an executable Interconnection Agreement within five (5) Business Days after the supplemental review screens are completed. Information regarding the Interconnection Agreement is detailed in Section 5.

If the proposed interconnection passes the supplemental review screens in Section 4.4 and the Interconnection Customer agrees to the non-binding good faith estimate of construction of any distribution or transmission facilities by the Area EPS Operator, the Area EPS Operator shall provide an executable Interconnection Agreement within twenty (20) Business Days. Included with the Interconnection Agreement shall be non-binding good faith estimate of construction costs and a construction schedule for the facilities. Information regarding the Interconnection Agreement is detailed in Section 5.

If the proposed interconnection does not pass the supplemental review screens in Section 4.4 the Area EPS Operator shall provide the Interconnection Customer with the option of commencing the Study Process. The Interconnection Customer shall notify the Area EPS Operator within fifteen (15) Business Days if they wish to proceed with the Study Process to retain their queue position or the Interconnection Application will be deemed withdrawn.

5 Interconnection Agreement

5.1. Uniform Contract

For proposed interconnections that do not meet the conditions of being classified as a qualifying facility less than 40 kW or if requested by the Interconnection Customer in lieu of signing the Uniform Contract, the Area EPS Operator shall provide the Interconnection Customer an executable Municipal Minnesota Interconnection Agreement (MMIA).

5.2. Municipal Minnesota Interconnection Agreement

If requested for proposed interconnections of a qualifying facility less than 40 kW, the Area EPS Operator shall provide the Interconnection Customer an executable copy of the Municipal Minnesota Interconnection Agreement (MMIA).

5.3. Minnesota Municipal Power Agency Distributed Generation Tariff and Acknowledgement Addendum

For a proposed interconnection of a Qualifying Facilities over 40kW, the City of Olivia Municipal Utilities appoints Minnesota Municipal Power Agency as the agency to purchase power. The Area EPS Operator shall provide the Interconnection Customer with an executable copy of the Minnesota Municipal Power Agency Distributed Generation Tariff in addition to the MMIA.

5.4. Completion of Agreement

The Interconnection Customer must return a signed Interconnection Agreement at least thirty (30) Business Days prior to the requested in-service date of the proposed DER. The Area EPS Operator shall sign and return a copy of the fully executed Interconnection Agreement back to the Interconnection Customer.

The Interconnection Customer may update the requested in-service date submitted on the Interconnection Application to a date thirty (30) Business Days or later from the date on which the Interconnection Customer submits a signed Interconnection Agreement and payment if required unless the Area EPS Operator agrees to an earlier date.

Upon receipt of the signed Interconnection Agreement, the Area EPS Operator may schedule appropriate metering replacements and construction of facilities, if necessary.

6 Insurance

6.1. Insurance Requirements

At minimum, the Interconnection Customer shall maintain, for the duration the DER system is interconnected to the Area EPS Operator's Distribution System, general liability insurance from a qualified insurance agency with a B+ or better rating by "Best" with a combined single limit of not less than those described in Table 6.1. Such general liability insurance shall include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Interconnection Customer's ownership and/or operation of the DER under this agreement. Evidence of the insurance shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance by the Area EPS Operator.

Table 6.1. Liability Insurance Requirements

DER System Size	Liability Insurance Requirement
< 40 kW AC	$300,000
≥ 40 kW AC and < 250 kW AC	$1,000,000
≥ 250 kW AC and < 5 MW AC	$2,000,000
≥ 5 MW AC	$3,000,000

For all proposed DER systems, except those that are qualifying systems less than 40 kW AC, the general liability insurance shall, by endorsement to the policy or polices:

- Include the Area EPS Operator as additionally insured.
- Contain severability of interest clause or cross-liability clause.
- Provide that the Area EPS Operator shall not by reason incur liability to the insurance carrier for the payment of premiums for such insurance if the Area EPS Operator is included as an additionally insured.

6.2. Self-Insurance

The Interconnection Customer may choose to be self-insured provided there is an established record of self-insurance. The Interconnection Customer shall supply the Area EPS Operator at least 20 days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required in Section 6.1. Failure of the Interconnection Customer or the Area EPS Operator to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

6.3. Proof of Insurance

The Interconnection Customer shall furnish the required insurance certificates and endorsements to the Area EPS Operator prior to the initial operation of the DER. A copy of the Declaration page of the Homeowner's insurance policy is a common example of an insurance certificate. Thereafter, the Area EPS Operator shall have the right to periodically inspect or obtain a copy of the original policy or polices of insurance. Additionally, the Area EPS Operator may request to be additionally listed as an interested third party on the insurance certificates and endorsements for qualifying facilities less than 40 kW AC to meet the right to periodically obtain a copy of the policy or policies of insurance.

7 Timeline Extensions

7.1. Reasonable Efforts

The Area EPS Operator shall make Reasonable Efforts to meet all time frames provided in these procedures. If the Area EPS Operator cannot meet a deadline provided herein, it must notify the Interconnection Customer in writing within three (3) Business Days after the deadline to explain the reason for the failure to meet the deadline and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

7.2. Extensions

For applicable time frames described in these procedures, the Interconnection Customer may request in writing one extension equivalent to half of the time originally allotted (e.g., ten (10) Business Days for a twenty (20) Business Days original time frame) which the Area EPS Operator may not unreasonably refuse. No further extensions for the applicable time frame shall be granted absent a Force Majeure Event or other similarly extraordinary circumstance.

8 Modifications to Application

8.1. Procedures

At any time after the Interconnection Application is deemed complete, the Interconnection Customer or the Area EPS Operator may identify modifications to the proposed DER system that may improve costs and benefits (including reliability) of the proposed DER system and the ability for the Area EPS Operator to accommodate the proposed DER system. The Interconnection Customer shall submit to the Area EPS Operator in writing all proposed modifications to any information provided in the Interconnection Application. The Area EPS Operator cannot unilaterally modify the Interconnection Application.

8.2. Timelines

Within ten (10) Business Days of receipt of the proposed modification, the Area EPS Operator shall evaluate whether the proposed modification to the Interconnection Application constitutes a Material Modification. The definition in the Section 13 Glossary of the Process Overview document includes examples of what does and does not constitute a Material Modification.

The Area EPS Operator shall notify the Interconnection Customer in writing of the final determination of the proposed modification. For proposed modifications that are determined to be a Material Modification the Interconnection Customer may choose to either: 1) withdraw the proposed modification; or 2) proceed with a new Interconnection Application. The Interconnection Customer shall provide its determination in writing to the Area EPS Operator within ten (10) Business Days after being provided the Material Modification determination. If the Interconnection Customer does not provide its determination within the timeline, the Interconnection Application shall be considered withdrawn.

If the proposed modification is not determined to be a Material Modification, then the Area EPS Operator shall notify the Interconnection Customer in writing that the modification has been accepted and the Interconnection Customer shall retain its eligibility for interconnection, including its place in the queue.

9 Interconnection

9.1. Interconnection Milestones

For DER systems that are not a qualifying facility less than 40 kW AC, the Interconnection Customer and the Area EPS Operator shall agree on milestones for which each Party is responsible and list them in Attachment IV of the MMIA. To the greatest extent possible, the Parties will identify all design, procurement, installation and construction requirements associated with the project, and clear associated timelines, at the beginning of the design, procurement, installation and construction phase, or as early within the process as possible.

A Party's obligation under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party of the reason(s) for not meeting the milestone, propose the earliest reasonable alternative date in which this and future milestones will be met, and request appropriate amendments to the MMIA and its attachments. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless:

- The Party will suffer significant uncompensated economic or operational harm from the delay, or

- Attainment of the same milestone has previously been delayed, or

- The Party has reason to believe the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstance explained by the Party proposing the amendment.

If the Party affected by the failure to meet a milestone disputes the proposed extension, the affected Party may pursue dispute resolution as described in the Overview Process document.

9.2. Metering

Any metering requirements necessitated by the use of the DER system shall be installed at the Interconnection Customer's expense. The metering requirement costs will be included in the final invoice of interconnection costs to the Interconnection Customer. The Interconnection Customer is also responsible for metering replacement costs not covered in the Interconnection Customer's general customer charge. The Area EPS Operator may charge Interconnection Customers an ongoing metering-related charge for an estimate of ongoing metering-related costs specifically demonstrated.

9.3. Construction

The Interconnection Customer may proceed to construct (including operational testing not to exceed two hours) the DER system when the Area EPS Operator has approved the Interconnection Application. Upon receipt of a signed Uniform Contract or Interconnection Agreement the Area EPS Operator shall schedule and execute appropriate construction of facilities.

9.4. Inspection, Testing and Commissioning

Upon completing construction of the DER system, the Interconnection Customer will cause the DER system to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction. The Interconnection Customer shall then arrange for the inspection and testing of the DER system and the Customer's Interconnection Facilities prior to interconnection pursuant to Minnesota Interconnection Technical Requirements. Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards of Minnesota's Technical Requirements and Section 15 in the Overview Process.

The Interconnection Customer shall notify the Area EPS Operator of testing and inspection no fewer than five (5) Business Days in advance, or as may be agreed to by the Parties. The Interconnection Customer shall provide to the Area EPS Operator a testing procedure that will be followed on the day of testing and inspection no fewer than ten (10) Business Days prior to the testing and inspection date. The testing procedure should include tests and/or inspections to confirm the DER system will meet the technical requirements of interconnection. The Area EPS Operator shall review the testing procedure for completeness and shall notify the Interconnection Customer if the testing procedure fails to address components of the technical requirements for interconnection.

The Area EPS Operator shall send qualified personnel to the DER site to inspect the interconnection and witness the testing. Testing and inspection shall occur on a Business Day at a mutually agreed upon date and time. The Area EPS Operator may waive the right to witness the testing.

9.5. Interconnection Costs

9.4.1 Estimation of Interconnection Costs

The Interconnection Customer shall pay for the actual cost of the Interconnection Facilities and Distribution Upgrades along with the Area EPS Operator's cost to commission the proposed DER system. An estimate of the interconnection costs shall be stated in the Uniform Contract or in the MMIA in Attachment II as a detailed itemization of such costs. If Network Upgrades are required, the actual cost of the Network Upgrades, including overheads, shall be borne by the Interconnection Customer pursuant to the Transmission Provider and associated agreements.

9.4.2 Progressive Payment of Interconnection Costs

The Area EPS Operator shall bill the Interconnection Customer for the design, engineering, construction and procurement costs of the Interconnection Facilities and Upgrades described in the MMIA, Uniform Contract Attachment II on a monthly basis or other basis agreed upon by both Parties in the Interconnection Agreement. The Interconnection Customer shall pay each bill within twenty-one (21) Business Days or as agreed to in the Interconnection Agreement.

9.4.3 Final Accounting of Interconnection Facilities and Upgrade Costs

If distribution or transmission facilities required upgrades to accommodate the proposed DER system, the Area EPS Operator shall render the final interconnection cost invoice to the Interconnection Customer within eighty (80) Business Days (approximately four calendar months) of completing the construction and installation of the Area EPS Operator's Interconnection Facility and Upgrades. The Area EPS Operator shall provide the Interconnection Customer with a final accounting report identifying the difference between the actual Interconnection Customer's cost responsibility and the Interconnection Customer's previous aggregate payments to the Area EPS Operator for the specific DER system interconnection. Upon the final accounting submitted to the Interconnection Customer, the balance between the actual cost and previously aggregated payments shall be paid to the Area EPS Operator within twenty (20) Business Days. If the balance between the actual cost and previously aggregated payments is a credit, the Area EPS Operator shall refund the Interconnection Customer within twenty (20) Business Days.

9.4.4 Final Interconnection Costs without Facilities and Upgrades Needed

Within thirty (30) Business Days the final invoice for the interconnection costs shall be rendered to the Interconnection Customer once the proposed DER system has been commissioned by the Area EPS Operator, or upon the commissioning being waived by the Area EPS Operator. The Interconnection Customer shall make payment to the Area EPS Operator within twenty-one (21) Business Days of receipt, or as otherwise stated in the Interconnection Agreement.

9.6. Security of Payment

At the option of the Area EPS Operator, either the "Traditional Security" or the "Modified Security" method shall be used for assurance of payment of interconnection cost.

Under the Traditional Security method, the Interconnection Customer shall provide reasonable, adequate assurances of credit, including a letter of credit or personal guaranty of payment and performance from a creditworthy entity acceptable under the Area EPS Operator credit policy. The letter of credit shall also include procedures for the unpaid balance of the estimated amount shown in the Interconnection Agreement for the totality of all anticipated work or expense incurred by the Area EPS Operator associated with the Interconnection Application. The payment for these estimated costs shall be as follows:

- 1/3 of estimated costs shall be due no later than when the Interconnection Customer signs the Interconnection Agreement.

- An additional 1/3 of estimated costs shall be due prior to initial energization of the DER with the Area EPS Operator.

- Remainder of actual costs, incurred by Area EPS Operator, shall be due within thirty (30) Business Days from the date the bill is mailed by the Area EPS Operator after project completion.

Under the Modified Security method, at least twenty (20) Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Area EPS Operator's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Area EPS Operator, at the Interconnection Customer's option, a guaranty, letter of credit or other form of security that is reasonably acceptable to the Area EPS Operator and is consistent with the Minnesota Uniform Commercial Code. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Area EPS Operator's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Area EPS Operator under the Interconnection Agreement during its term.

The guaranty must be made by an entity that meets the creditworthiness requirements of the Area EPS Operator and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

The letter of credit must be issued by a financial institution or insurer reasonably acceptable to the Area EPS Operator and must specify a reasonable expiration date not sooner than sixty (60) Business Days (three calendar months) after the due date of the final accounting report and bill described in Section 9.5

9.7. Non-Warranty

Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, operated, installed or maintained by the Interconnection Customer, including without limitation the DER and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator. The Area EPS Operator does not guarantee uninterrupted power supply to the DER and will operate the Distribution System with the same reliability standards for the entire customer base.

9.8. Authorization for Parallel Operation

The Interconnection Customer shall not operate its DER system in parallel with the Area EPS Operator's Distribution System without prior written authorization from the Area EPS Operator. The Area EPS Operator shall provide such authorization within three (3) Business Days from when the Area EPS Operator receives notification that the Interconnection Customer has complied with all applicable parallel operations requirements and commissioning has been successfully completed. Such authorization shall not be unreasonably withheld, conditioned or delayed.

9.9. Continual Compliance

The Interconnection Customer shall be fully responsible to operate, maintain, and repair the DER as required to ensure that it complies at all times with the interconnection standards to which it has been certified. The Interconnection Customer shall also operate its DER system in compliance with the Area EPS Operator's technical requirements referred to in the executed Interconnection Agreement. The Area EPS Operator may periodically inspect, at its own expense, the operation of the DER system as it relates to power quality, thermal limits and reliability. Failure by the Interconnection Customer to remain in compliance with the technical requirements will result in the disconnection of the DER system from the Area EPS Operator's Distribution System.

9.10. Disconnection of DER

The Area EPS Operator has the right to disconnect the DER in the event of the following:

- Does not continue to follow and maintain IEEE 1547 settings approved by the Area EPS Operator as indicated by the adopted technical requirements.

- Does not meet all the requirements of the Fast Track Process.

- Refuses to sign the MMIA, the Area EPS Operator’s Uniform Contract, or the MMPA Tariff.

The Area EPS Operator may temporarily disconnect the DER upon the following conditions:

- For scheduled outages upon reasonable notice.
- For unscheduled outages or emergency conditions.
- If the DER does not operate in the manner consistent with the Fast Track Process.

The Area EPS Operator shall inform the Interconnection Customer in advance of any scheduled disconnections, or as reasonable, after an unscheduled disconnection.

Southern Minnesota Municipal Power Agency's
5 MW Lemond Solar Station
Owatonna, MN

INTERCONNECTION PROCESS

Study Process

ABSTRACT

Information in addition to the "Process Overview" for interconnecting to the utility distribution system Distributed Energy Resources larger than 4 megawatts in size or in need of additional studies.

Contents

1 Applicability

1.1. Applicability

The Study Process is applicable to an Interconnection Customer proposing to interconnect a Distributed Energy Resource (DER) with the Area Electrical Power System (Area EPS) Operator's Distribution System, if the DER capacity is larger than 4 MW or is identified through the engineering screening process to need additional studies.

The majority of proposed DER interconnections will initially apply for interconnection under the Simplified or Fast Track Processes. Initial and supplemental screening results are to be considered throughout the Study Process.

1.2. Codes, Standards and Certification Requirements

The Interconnection Customer's proposed DER must meet the codes, standards and certification requirements listed in Section 13, 14 and Section 15 of the Process Overview document. The Area EPS Operator may allow DER systems that do not meet codes, standards and certification only if the DER system design is reviewed, tested and determined to be safe to operate in parallel with the Distribution System.

2 Application Submission

2.1. Initial Interconnection Application for the Study Process

For proposed DER interconnections that are not initially applied for under the Fast Track Process, the Interconnection Customer shall complete the Standard Interconnection Application and submit it to the Area EPS Operator to initiate the Interconnection Process. A completed Interconnection Application will include the following:

- A completed Interconnection Application signed by the Interconnection Customer.
- A process fee not to exceed $1,000, plus $2.00 per kW, toward the deposit of the study(s) indicated in Section 4.
- A site layout drawing of the proposed DER system.
- A one-line diagram of the proposed DER system showing the Point of Common Coupling to the Area EPS Operator's Distribution System.
- All equipment manufacturer specification sheets.
- Documentation of site control as indicated in Section 2.4.

2.2. Professional Licensed Engineer Signature

The one-line diagram submitted with the Interconnection Application will require a signature from a professional engineer licensed in the State of Minnesota certifying the DER was designed in conformance to the Minnesota Technical Requirements for the following conditions:

- Certified[1] equipment is greater than 250 kW.
- Non-certified equipment is greater than 20 kW.

2.3. Battery Storage

An inverter-based DER system may include battery storage. DER systems that include battery storage should complete the Energy Storage Application along with the Interconnection Application.

2.4. Site Control

Documentation of site control must be submitted with the Interconnection Application. Site control may be demonstrated by any of the following:

- Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the DER system;
- An option to purchase or lease a site for constructing the DER system;
- An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for constructing the DER system.

2.5. Interconnection Applications from Other Processes

Some Interconnection Applications submitted under the Fast Track Process may be moved into the Study Process due to issues with the DER interconnection identified by engineering screens. An Area EPS Operator cannot request a new Interconnection Application submission if the Interconnection Application has already been submitted through the Fast Track Process. The Interconnection Customer who had already paid a processing fee for the Fast Track Process is still responsible to make a deposit toward the applicable studies addressed in Sections 4, 5 and 6, but does not need to submit an additional processing fee.

[1] Additional information regarding certified equipment is found in Sections 14 and 15 of the Process Overview document.

3 Initial Steps

3.1. Completeness Review and Queue Position

The Interconnection Application originally submitted under the Study Process shall be date- and time-stamped upon initial receipt, and if necessary, resubmission receipt. The Interconnection Customer shall be notified of receipt by the Area EPS Operator within ten (10) Business Days after receipt.

The Area EPS Operator shall notify the Interconnection Customer, within ten (10) Business Days, if the Interconnection Application is deemed incomplete, and provide a written list detailing all information that must be provided to complete the Interconnection Application. The Interconnection Customer has ten (10) Business Days, to provide the missing information, unless additional time is requested with a valid reason. Failure to submit the requested information, within the stated timeline, will result in the Interconnection Application being deemed withdrawn. The Area EPS Operator has an additional five (5) Business Days to review the additionally provided information for completeness.

An Interconnection Application will be deemed complete upon submission to the Area EPS Operator, provided all documents, fees and information required with the Interconnection Application, adhering to Minnesota Technical Requirements, is included. The date- and time-stamp of the completed Interconnection Application shall be accepted as the qualifying date for the purpose of establishing a queue position, as described in Section 4.7 of the Overview Process document.

Interconnection Applications already screened in the Simplified Process or Fast Track Process shall retain their original queue position in the Study Process provided all applicable timelines were met.

3.2. Scoping Meeting

A scoping meeting shall be held within ten (10) Business Days after the Interconnection Application submitted under the Study Process is deemed complete. For Interconnection Applications that were submitted under or put through the Fast Track Process, the scoping meeting will occur within ten (10) Business Days after the Interconnection Customer has elected to continue with the Study Process. The scoping meeting timeline may be extended upon mutual agreement of both Parties. The scoping meeting may also be omitted by mutual agreement.

The purpose of the scoping meeting is to discuss the Interconnection Application and review existing study results relevant to the Interconnection Application. The Parties shall further discuss whether the Area EPS Operator should perform a System Impact

Study or Studies, or proceed directly to a Facilities Study or an Interconnection Agreement. If the Area EPS Operator determines there is no potential for Transmission System or Distribution System adverse system impacts, the Interconnection Application shall proceed directly to a Facilities Study or an executable Interconnection Agreement, as agreed to by the Parties.

4 System Impact Study

4.1. Electric System Impacts

A System Impact Study shall identify and detail the electric system impacts that would result if the proposed DER(s) were interconnected without project modifications or electric system modifications. The System Impact Study is also to study the potential impacts, including but not limited to, those identified in the scoping meeting. A System Impact Study shall evaluate the impacts of the proposed interconnection on the reliability of the electric system.

4.2. System Impact Study Agreement

If the Parties agree at the scoping meeting that a System Impact Study should be performed, the Area EPS Operator shall provide the Interconnection Customer a System Impact Study Agreement, not later than five (5) Business Days after the scoping meeting. If the scoping meeting was omitted by mutual agreement, the Area EPS Operator shall provide the Interconnection Customer a System Impact Study Agreement within ten (10) Business Days after the Interconnection Customer waives the scoping meeting.

The System Impact Study Agreement shall include an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If applicable, the System Impact Study Agreement shall list any additional and reasonable technical data on the DER needed to perform the study. The scope and cost responsibilities are to be described in the System Impact Study Agreement.

4.3. System Impact Study Costs

A deposit of the good faith estimated cost for each System Impact Study shall be provided by the Interconnection Customer with the return of a signed System Impact Study Agreement.

4.4. System Impact Study Timelines

Both the Area EPS Operator and the Interconnection Customer have timeline responsibilities under the System Impact Study.

4.4.1. Interconnection Customer Timelines

In order to remain in consideration for interconnection, an Interconnection Customer who has requested a System Impact Study shall meet the following conditions within twenty (20) Business Days of being provided a System Impact Study Agreement:

- Return a signed System Impact Study Agreement.

- Provide to the Area EPS Operator any requested additional and reasonable technical data on the DER needed to perform the System Impact Study.

- Pay the required study deposit.

Upon the Interconnection Customer's request, the Area EPS Operator shall grant a time frame extension as described in Section 9.29.2, if additional technical data is requested.

4.4.2 Area EPS Operator Timelines

A System Impact Study shall be completed within thirty (30) Business Days after the System Impact Study Agreement has been signed by both Parties and delivered with the deposit and requested technical information to the Area EPS Operator. The results of the System Impact Study shall be delivered to the Interconnection Customer within five (5) Business Days of completion of the System Impact Study. Upon request, the Area EPS Operator shall provide the Interconnection Customer supporting documentation developed in the preparation of the System Impact Study, subjected to confidentiality arrangements consistent with Section 12.1 of the Overview Process and terms of the System Impact Study Agreement.

5 Transmission System Impact Study

5.1. Transmission System Impacts

In instances where the System Impact Study shows potential for Transmission System adverse system impacts, the Area EPS Operator shall contact the appropriate Transmission Provider within five (5) Business Days following the identification of such impacts. The Area EPS Operator shall coordinate with the Area EPS Operator's Transmission Provider to have the necessary studies to determine if the DER causes any adverse transmission impacts. The appropriate Transmission Provider shall provide a Transmission System Impact Study Agreement for the Interconnection Customer. Included in the Transmission System Impact Study Agreement will be a non-binding, good faith estimate of cost for the study, along with a scope outline of the study and any additional technical data required to complete the Transmission System Impact Study.

5.2. Transmission System Impact Study Timelines

In order to remain in consideration for interconnection, an Interconnection Customer must return the executed Transmission System Impact Study Agreement, along with the study deposit, within fifteen (15) Business Days. The Transmission System Impact Study shall be completed and the results provided to the Interconnection Customer in as timely a manner as possible, after the Transmission System Impact Study Agreement is signed by the Parties. The Area EPS Operator shall be responsible for coordination with the Transmission Provider as needed. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

5.3. Regional Transmission Operator Jurisdiction

In certain circumstances the Transmission Provider may not be able to study a proposed DER system if there is a possible affect to the bulk Transmission System. In these situations, the Area EPS Operator will coordinate with the Transmission Provider to inform the Interconnection Customer that the proposed DER system will need to follow the Regional Transmission Operator's interconnection process. For most of Minnesota, the Regional Transmission Operator is Midcontinent Independent System Operator (MISO).

6 Facilities Study

6.1. Construction of Facilities

If construction of facilities is required, a Facility Study may be necessary to specify and estimate the cost of the equipment, engineering, procurement and construction work. A Facility Study is identified by an Initial Review, Supplemental Review or the Study Process to provide interconnection and interoperability of the DER with the Area EPS Operator's Distribution System as required by Minnesota Technical Requirements. At the determination of the Area EPS Operator, Interconnection Applications reviewed in the Simplified Process or the Fast Track Process that require construction of facilities may forgo a Facilities Study.

6.2. Facilities Study Agreement

The Area EPS Operator shall provide the Interconnection Customer a Facilities Study Agreement either:

- in tandem with the results of the Interconnection Customer's System Impact Study, or
- in tandem with a Transmission System Impact Study, or
- if no System Impact Study is required, within five (5) Business Days after the scoping meeting, or
- within ten (10) Business Days after the Interconnection Application is deemed complete and approved through the Simplified Process or Fast Track Process.

The Facilities Study Agreement shall be accompanied by an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the Facilities Study. The scope of and cost responsibilities for the Facilities Study are to be described in the Facilities Study Agreement. A deposit of the good faith estimated costs for the Facilities Study shall be provided by the Interconnection Customer at the time it returns the Facilities Study Agreement.

6.3. Facilities Study Timeline

In order to remain under consideration for interconnection, the Interconnection Customer must return the executed Facilities Study Agreement and pay the required study deposit within fifteen (15) Business Days.

6.4. Identification of Construction of Facilities

The Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads), needed to implement the conclusions of the System Impact Study(-ies). Design for any required Interconnection Facilities and/or Upgrades shall be performed under the Facilities Study Agreement unless the Facilities Study Agreement was deemed unnecessary by the Area EPS Operator. However, in the event that the Interconnection Customer did not provide the Area EPS Operator all required Conditional Use Permits at the time of entering into the Facilities Study Agreement, any such Design and/or Upgrades by the Area EPS Operator may be delayed until after the Interconnection Customer has provided to the Area EPS Operator all required Conditional Use Permits or provides a final design. The information in the Conditional Use Permits, or changes to the design, may result in significant modifications to the planned design and/or Upgrades. The Interconnection Customer may send to the Area EPS Operator a redacted version of the Conditional Use Permit(s) to ensure confidentiality, but any and all information that the Area EPS Operator would reasonably need to perform an accurate Facilities Study shall not be redacted. If necessary to comply with these requirements, a confidential version of the

Conditional Use Permit(s) may be provided to the Area EPS Operator, with the confidential information being clearly marked and subjected to Confidentiality provisions in the Overview Process document Section 12.1.

The Area EPS Operator may contract with consultants to perform activities required under the Facilities Study Agreement. The Interconnection Customer and the Area EPS Operator may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Area EPS Operator, under the provisions of the Facilities Study Agreement. The Area EPS Operator shall make sufficient information available to the Interconnection Customer, in accordance with confidentiality and critical infrastructure requirements, to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

6.5. Facilities Study Report Timeline

In cases where Upgrades are required, the Facilities Study must be completed within forty-five (45) Business Days of the receipt of the executed Facilities Study Agreement and deposit. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the Facilities Study must be completed within thirty (30) Business Days of the receipt of the executed Facilities Study Agreement and deposit.

Once the Facilities Study is completed, a draft Facilities Study Report shall be prepared and transmitted to the Interconnection Customer. Upon request, the Area EPS Operator shall provide the Interconnection Customer supporting documentation developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with these procedures and the Facilities Study Agreement.

Within ten (10) Business Days of providing a draft Facilities Study Report to the Interconnection Customer, the Area EPS Operator and Interconnection Customer shall meet to discuss the results of the Facilities Study. This meeting may be omitted by mutual agreement. The Interconnection Customer may, within twenty (20) Business Days after receipt of the draft report, provide written comments to the Area EPS Operator, which the Area EPS Operator shall address in the final report.

The Area EPS Operator shall issue the final Facilities Study Report within fifteen (15) Business Days of receiving the Interconnection Customer’s comments, or promptly upon receiving the Interconnection Customer’s statement that they will not provide comments. The Area EPS Operator may reasonably extend the time frame, upon notice to the Interconnection Customer, if the Interconnection Customer's comments require additional analyses or lead to significant modifications by the Area EPS Operator prior to issuance of the final Facilities Study Report.

7 Interconnection Agreement

7.1. Uniform Contract

For a proposed interconnection that meets the conditions of being classified as a qualifying facility less than 40 kW, the Area EPS Operator shall provide the Interconnection Customer with an executable copy of the Area EPS Operator's Uniform Contract for Cogeneration and Small Power Production Facilities (Uniform Contract), within five (5) Business Days after the completion of the applicable study(-ies).

7.2. Municipal Minnesota Interconnection Agreement

For proposed interconnections that do not meet the conditions of being classified as a qualifying facility less than 40 kW or if requested by the Interconnection Customer in lieu of signing the Uniform Contract, the Area EPS Operator shall provide the Interconnection Customer an executable Municipal Minnesota Interconnection Agreement (MMIA) within five (5) Business Days after the completion of the applicable study(-ies).

7.3. Minnesota Municipal Power Agency Distributed Generation Tariff and Acknowledgement Addendum

For a proposed interconnection of a Qualifying Facilities over 40kW, the City of Olivia Municipal Utilities appoints Minnesota Municipal Power Agency as the agency to purchase power. The Area EPS Operator shall provide the Interconnection Customer with an executable copy of the Minnesota Municipal Power Agency Distributed Generation Tariff in addition to the MMIA.

7.4. Completion of Agreement

The Interconnection Customer must return a signed Interconnection Agreement at least thirty (30) Business Days prior to the requested in-service date of the propose DER. The Area EPS Operator shall sign and return a copy of the fully executed Interconnection Agreement, back to the Interconnection Customer.

The Interconnection Customer may update the requested in-service date submitted on the Interconnection Application to a date thirty (30) Business Days or later from the date on which the Interconnection Customer submits a signed Interconnection Agreement and payment if required unless the Area EPS Operator agrees to an earlier date.

Upon receipt of the signed Interconnection Agreement, the Area EPS Operator may schedule appropriate metering replacements and construction of facilities, if necessary.

8 Insurance

8.1. Insurance Requirements

At minimum, the Interconnection Customer shall maintain, for the duration the DER system is interconnected to the Area EPS Operator's Distribution System, general liability insurance from a qualified insurance agency with a B+ or better rating by "Best," with a combined single limit of not less than those described in Table 8.1. Such general liability insurance shall include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Interconnection Customer's ownership and/or operation of the DER under this agreement. Evidence of the insurance shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance by the Area EPS Operator.

Table 8.1 Liability Insurance Requirements

DER System Size	Liability Insurance Requirement
< 40 kW AC	$300,000
≥ 40 kW AC and < 250 kW AC	$1,000,000
≥ 250 kW AC and < 5 MW AC	$2,000,000
≥ 5 MW AC	$3,000,000

For all proposed DER systems, except those that are qualifying systems less than 40 kW AC, the general liability insurance shall, by endorsement to the policy or polices:

- Include the Area EPS Operator as additionally insured.
- Contain severability of interest clause or cross-liability clause.
- Provide that the Area EPS Operator shall not by reason incur liability to the insurance carrier for the payment of premiums for such insurance if the Area EPS Operator is included as an additionally insured.

8.2. Self-Insurance

The Interconnection Customer may choose to be self-insured provided there is an established record of self-insurance. The Interconnection Customer shall supply the Area EPS Operator at least twenty (20) Business Days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required in Section 8.1. Failure of the Interconnection Customer or the Area EPS Operator to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

8.3. Proof of Insurance

The Interconnection Customer shall furnish the required insurance certificates and endorsements to the Area EPS Operator prior to the initial operation of the DER. A copy of the Declaration page of the homeowner's insurance policy is a common example of an insurance certificate. Thereafter, the Area EPS Operator shall have the right to periodically inspect or obtain a copy of the original policy or polices of insurance. Additionally, the Area EPS Operator may request to be additionally listed as an interested third party on the insurance certificates and endorsements for qualifying facilities less than 40 kW AC, to meet the right to periodically obtain a copy of the policy or policies of insurance.

9 Timeline Extensions

9.1. Reasonable Efforts

The Area EPS Operator shall make Reasonable Efforts to meet all the time frames provided in these procedures. If the Area EPS Operator cannot meet a deadline provided herein, it must notify the Interconnection Customer in writing within three (3) Business Days after the deadline, explaining the reason for the failure to meet the deadline and providing an estimated time by which it will complete the applicable interconnection procedure in the process.

9.2. Extensions

For applicable time frames described in these procedures, the Interconnection Customer may request in writing one extension equivalent to half of the time originally allotted (e.g., ten (10) Business Days for a twenty (20) Business Days original time frame), which the Area EPS Operator may not unreasonably refuse. No further extensions for the applicable time frame shall be granted, absent a Force Majeure Event or other similarly extraordinary circumstance.

10 Modifications to Application

10.1. Procedures

At any time after the Interconnection Application is deemed complete, the Interconnection Customer or the Area EPS Operator may identify modifications to the proposed DER system that may improve costs and benefits. This includes reliability of the proposed DER system and the ability for the Area EPS Operator to accommodate the proposed DER system. The Interconnection Customer shall submit to the Area EPS

Operator, in writing, all proposed modifications to any information provided in the Interconnection Application. The Area EPS Operator cannot unilaterally modify the Interconnection Application.

10.2. Timelines

Within ten (10) Business Days of receipt of the proposed modification, the Area EPS Operator shall evaluate whether the proposed modification to the Interconnection Application constitutes a Material Modification. The definition in the Section 13 Glossary of the Process Overview document includes examples of what does and does not constitute a Material Modification.

The Area EPS Operator shall notify the Interconnection Customer in writing of the final determination of the proposed modification. For proposed modifications that are determined to be a Material Modification the Interconnection Customer may choose to either: 1) withdraw the proposed modification; or 2) proceed with a new Interconnection Application. The Interconnection Customer shall provide its choice in writing to the Area EPS Operator within ten (10) Business Days after being provided the Material Modification determination. If the Interconnection Customer does not provide its choice within the timeline, the Interconnection Application shall be considered withdrawn.

If the proposed modification is not determined to be a Material Modification, then the Area EPS Operator shall notify the Interconnection Customer in writing that the modification has been accepted and the Interconnection Customer shall retain its eligibility for interconnection, including its position in the queue.

11 Interconnection

11.1. Interconnection Milestones

For DER systems that are not a qualifying facility less than 40 kW AC, the Interconnection Customer and the Area EPS Operator shall agree on milestones for which each Party is responsible and list them in Attachment IV of the MMIA. To the greatest extent possible, the Parties will identify all design, procurement, installation and construction requirements associated with the project while also clearly identifying associated timelines, at the beginning, or as early within the process as possible, of the design, procurement, installation and construction phase.

A Party’s obligation under this provision may be extended by agreement. If a Party anticipates that they will be unable to meet a milestone for any reason other than a Force Majeure Event, they shall immediately notify the other Party of the reason(s) for not meeting the milestone, then propose the earliest reasonable alternative date in which this and future milestones will be met and request appropriate amendments to the Interconnection Agreement and its attachments. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless:

- The Party will suffer significant uncompensated economic or operational harm from the delay, or

- Attainment of the same milestone has previously been delayed, or

- The Party has reason to believe the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstance explained by the Party proposing the amendment.

If the Party affected by the failure to meet a milestone disputes the proposed extension, the affected Party may pursue dispute resolution as described in the Overview Process document.

11.2. Metering

Any metering requirements necessitated by the use of the DER system shall be installed at the Interconnection Customer's expense. The metering-related costs will be included in the final invoice of interconnection costs to the Interconnection Customer. The Interconnection Customer is also responsible for metering replacement costs not covered in the Interconnection Customer's general customer charge. The Area EPS Operator may charge Interconnection Customers an ongoing metering-related charge for an estimate of ongoing metering-related costs specifically demonstrated.

11.3. Inspection, Testing and Commissioning

Upon completing construction of the DER system, the Interconnection Customer will cause the DER system to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction. The Interconnection Customer shall then arrange for the inspection and testing of the DER system and the Customer's Interconnection Facilities prior to interconnection pursuant to Minnesota Technical Requirements. Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards of Minnesota's Technical Requirements and Section 15 in the Overview Process.

The Interconnection Customer shall notify the Area EPS Operator of testing and inspection no fewer than five (5) Business Days in advance, or as may be agreed to by the Parties. The Interconnection Customer shall provide to the Area EPS Operator a testing procedure that will be followed on the day of testing and inspection no fewer than ten (10) Business Days prior to the testing and inspection date. The testing procedure should include tests and/or inspections to confirm the DER system will meet the technical requirements of interconnection. The Area EPS Operator shall review the testing procedure for completeness and notify the Interconnection Customer if the testing procedure fails to address components of the technical requirements for interconnection.

The Area EPS Operator shall send qualified personnel to the DER site to inspect the interconnection and witness the testing. Testing and inspection shall occur on a Business Day at a mutually agreed upon date and time. The Area EPS Operator may waive the right to witness the testing.

11.4. Interconnection Costs

11.4.1 Estimation of Interconnection Costs

The Interconnection Customer shall pay for the actual cost of the Interconnection Facilities and Distribution Upgrades along with the Area EPS Operator’s cost to commission the proposed DER system. An estimate of the interconnection costs shall be stated in the Uniform Contract or in the MMIA in Attachment II, Interconnection Facilities and Upgrades, as a detailed itemization of such costs. If Network Upgrades are required, the actual cost of the Network Upgrades, including overheads, shall be borne by the Interconnection Customer pursuant to the Transmission Provider and associated agreements.

11.4.2 Progressive Payment of Interconnection Costs

The Area EPS Operator shall invoice the Interconnection Customer for the design, engineering, construction and procurement costs of the Interconnection Facilities and Upgrades described in the MMIA Attachment II, on a monthly basis, or other manner agreed upon by both Parties in the MMIA, or as described in the Uniform Contract. The Interconnection Customer shall pay each invoice within twenty-one (21) Business Days or as agreed to in the Interconnection Agreement.

11.4.3 Final Accounting of Interconnection Facilities and Upgrade Costs

If distribution or transmission facilities required upgrades to accommodate the proposed DER system, the Area EPS Operator shall render the final interconnection cost invoice to the Interconnection Customer within eighty (80) Business Days (approximately four calendar months) of completing the construction and installation of the Area EPS Operator’s Interconnection Facility and Upgrades. The Area EPS Operator shall provide the Interconnection Customer with a final accounting report identifying the difference between the actual Interconnection Customer's cost responsibility and the Interconnection Customer's previous aggregate payments to the Area EPS Operator for the specific DER system interconnection. Upon the final accounting submitted to the Interconnection Customer, the balance between the actual cost and previously aggregated payments shall be paid to the Area EPS Operator within twenty (20) Business Days. If the balance between the actual cost and previously aggregated payments is a credit, the Area EPS Operator shall refund the Interconnection Customer within twenty (20) Business Days.

11.4.4 Final Interconnection Costs without Facilities and Upgrades Needed

Within thirty (30) Business Days the final invoice for the interconnection costs shall be rendered to the Interconnection Customer once the proposed DER system has been commissioned by the Area EPS Operator, or upon the commissioning being waived by the Area EPS Operator. The Interconnection Customer shall make payment to the Area EPS Operator within twenty-one (21) Business Days of receipt, or as otherwise stated in the Interconnection Agreement.

11.5. Security of Payment

At the option of the Area EPS Operator, either the "Traditional Security" or the "Modified Security" method shall be used for assurance of payment of interconnection cost.

Under the Traditional Security method, the Interconnection Customer shall provide reasonable, adequate assurances of credit, including a letter of credit or personal guaranty of payment and performance from a creditworthy entity acceptable under the Area EPS Operator credit policy. The letter of credit shall also include procedures for the unpaid balance of the estimated amount shown in the Interconnection Agreement for the totality of all anticipated work or expense incurred by the Area EPS Operator associated with the Interconnection Application. The payment for these estimated costs shall be as follows:

- One-third of estimated costs, shall be due no later than when the Interconnection Customer signs the Interconnection Agreement.

- An additional one-third of estimated costs, shall be due prior to initial energization of the DER with the Area EPS Operator.

- After the project completion, the remainder of actual costs, incurred by Area EPS Operator, shall be due within thirty (30) Business Days from the date the invoice is mailed.

Under the Modified Security method, at least twenty (20) Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Area EPS Operator's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Area EPS Operator, at the Interconnection Customer's option, a guaranty, letter of credit or other form of security that is reasonably acceptable to the Area EPS Operator and is consistent with the Minnesota Uniform Commercial Code. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Area EPS Operator's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Area EPS Operator under the Interconnection Agreement during its term.

The guaranty must be made by an entity that meets the creditworthiness requirements of the Area EPS Operator and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

The letter of credit must be issued by a financial institution or insurer reasonably acceptable to the Area EPS Operator and must specify a reasonable expiration date not sooner than sixty (60) Business Days, (three calendar months), after the due date of the final accounting report and invoice described in Section 11.4.

11.6. Non-Warranty

Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, operated, installed or maintained by the Interconnection Customer, including without limitation the DER and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator. The Area EPS Operator does not guarantee uninterrupted power supply to the DER and will operate the Distribution System with the same reliability standards for the entire customer base.

11.7. Authorization for Parallel Operation

The Interconnection Customer shall not operate its DER system in parallel with the Area EPS Operator's Distribution System without prior written authorization from the Area EPS Operator. The Area EPS Operator shall provide such authorization within three (3)

Business Days from when the Area EPS Operator receives notification that the Interconnection Customer has complied with all applicable parallel operations requirements and commissioning has been successfully completed. Such authorization shall not be unreasonably withheld, conditioned or delayed.

11.8. Continual Compliance

The Interconnection Customer shall operate its DER system in compliance with the Area EPS Operator’s technical requirements referred to in the executed Interconnection Agreement. The Area EPS Operator may periodically inspect, at its own expense, the operation of DER system as it relates to power quality, thermal limits and reliability. Failure by the Interconnection Customer to remain in compliance with the technical requirements will result in the disconnection of the DER system from the Area EPS Operator’s Distribution System.

11.9. Disconnection of DER

The Area EPS Operator has the right to disconnect the DER in the event of the following:

- Does not continue to follow and maintain IEEE 1547 settings approved by the Area EPS Operator as indicated by the adopted technical requirements.
- Does not meet all the requirements of the Study Process.
- Refuses to sign the MMIA, the Area EPS Operator’s Uniform Contract, or the MMPA Tariff.

The Area EPS Operator may temporarily disconnect the DER upon the following conditions:

- For scheduled outages upon reasonable notice.
- For unscheduled outages or emergency conditions.
- If the DER does not operate in the manner consistent with the Study Process.

The Area EPS Operator shall inform the Interconnection Customer in advance of any scheduled disconnections, or as reasonable, after an unscheduled disconnection.

STATE OF MINNESOTA TECHNICAL INTERCONNECTION AND INTEROPERABILTY REQUIREMENTS

TIIR

Abstract

The technical requirements for interconnection of Distributed Energy Resources to the distribution system to be used in conjunction with electric utilities' Technical Specification Manuals

Approved by Commission's Order dated January 22, 2020

Contents

1. Overview

1.1 General

Distributed Energy Resources (DER) connected to the electric distribution system span a wide range of sizes and electrical characteristics utilizing technology that is constantly evolving. The design of electrical distribution systems varies widely from that which is required to serve the rural customer to that which is needed to serve the large commercial customer.

The electric distribution system is designed to operate in both normal and contingency configurations. Normal system configurations or normal operation exists when all distribution facilities and equipment are available and fully functional and the Area EPS's switches are in their normal state. Contingency system configuration or contingency operation is the condition in which the failure of a single or multiple element(s) affect the normal operation of the Area EPS or when the Area EPS's switch positions are in the abnormal state. Contingency configurations can arise from electric component failures or from planned maintenance.

The scope of this document, referred to as the Technical Interconnection and Interoperability Requirements (TIIR), is to describe common statewide requirements for interconnection of DER systems with the Area EPS. The Area EPS's specific specifications or technology requirements are detailed with the Area EPS Operator's Technical Specification Manual (TSM). Both the TIIR and the TSM documents are based upon the IEEE 1547 standards and other applicable national standards. The intent of these documents is to provide consumers and installers with a clear set of technical requirements and guide the interconnection of DER systems with the local electrical distribution system using a safe, reliable, and cost-effective design.

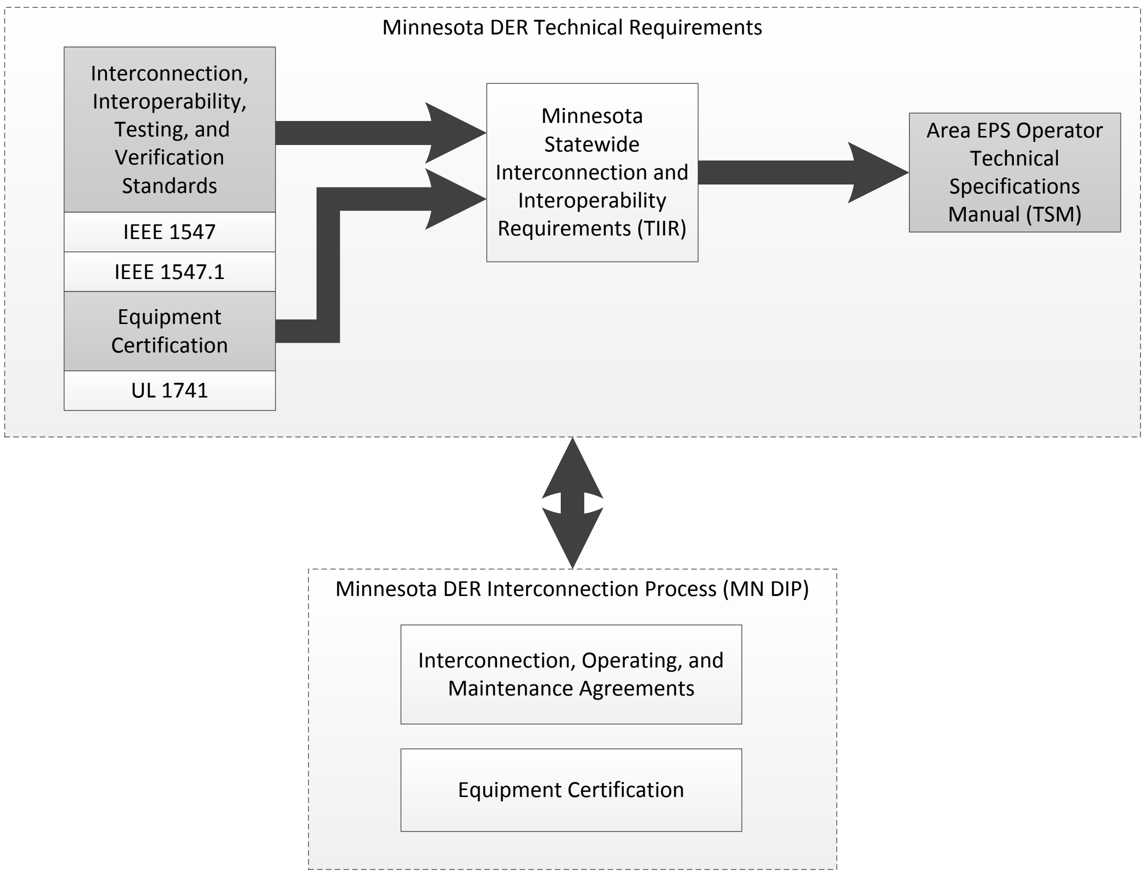
With so many variations in Area EPS designs, it becomes complex to create a single set of interconnection requirements that fits all DER interconnection situations. The Area EPS Operator must maintain a level of engineering judgment in order to interconnect the wide range of technologies over a variety of Area EPS and DER characteristics and designs[1]. The Area EPS Operator shall follow applicable industry standards and good utility practice when applying engineering judgment.

This document sets forth statewide technical requirements for DER interconnecting to an Area EPS in the state of Minnesota. The Minnesota statewide TIIR have been established to align with the Area EPS Operators' duty and obligation to plan and operate a distribution system that economically delivers electric power while focusing on safety, reliability, and quality of service.

[1] Another factor driving the need for engineering judgment is the increasingly varied mixture of legacy DER equipment from different era standards. Currently national standards do not exist to address interconnection engineering considerations that may arise due the mix of current and legacy technology. For example, a portion of the Area EPS with legacy inverters and advanced inverters will respond differently to abnormal conditions when compared to apportion of the Area EPS that contains only advanced inverters. Legacy inverters are grandfathered in under the standards under which they were installed.

The statewide TIIR shall be used in conjunction with individual Area EPS Operator interconnection Technical Specification Manuals (TSM). Where industry standards exist, the TSM shall align with the applicable standards including IEEE 1547. The TSM also lists the Area EPS Operator specific requirements and provides further detail in areas where no common statewide or national industry standards exist[2]. In addition to allowing for differences in distribution electric and information systems design and operation, the Area EPS Operator's TSM allows for expedited adoption of new industry standards and best practices as they become available without creating conditions where the statewide interconnection standards and national standards become out-of-sync. Figure 1 depicts the interaction of key DER industry technical standards, statewide technical standards (TIIR), Area EPS Operator's technical specifications manuals (TSMs), and the Minnesota Distributed Energy Resources Interconnection Process (MN DIP).

Figure 1. Interaction of DER Standards



All requirements in the most recent versions of IEEE 1547 and 1547.1 are adopted by the TIIR. IEEE 1547, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, and IEEE 1547.1, *IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems*, provides the foundation of interconnection and

[2] For example, industry standards do not define conditions or size thresholds for when metering, interoperability, protection, or other requirements shall be applied. Also, interconnection standards only address the electrical and interoperability interface between the Local EPS and Area EPS.

interoperability technical requirements which applies to all DER interconnections. Other standards, recommended practices, and guide documents may be applicable to individual projects and should be referenced based on the DER technology and configuration being proposed and characteristics of the Area EPS[3] to which it is being interconnected. In general, the content of industry standards is not reproduced here, but instead the additional standards are referenced in Section 3 of this document.

Consistent with IEEE 1547, these requirements apply to the interconnection of all DER units within the Local EPS that parallel with the Area EPS. The requirements in the TIIR shall be applied at the Reference Point of Applicability (RPA)[4], unless otherwise specified by the TIIR or mutually agreed upon. The DER shall not create or contribute to an intentional Area EPS island, unless approved by the Area EPS Operator.

When the need arises, the Area EPS should coordinate with Transmission Providers and Regional Transmission Operators to accommodate requests from these entities which cross the transmission and distribution electric interface while still maintaining the Area EPS Operators' primary responsibility of providing safe, reliable, and quality service for Area EPS retail customers.

Protection systems requirements in the TIIR, are structured to protect the Area EPS, Area EPS customers, and the public. Details of protection systems requirements are specified in the Area EPS Operator's TSM. The protection of the DER and the Local EPS is solely the responsibility of the Interconnection Customer and is not addressed in these technical requirements.

The DER Operator shall be responsible for complying with all applicable local, independent, state and federal codes such as building codes, National Electric Code (NEC), National Electrical Safety Code (NESC) and local municipality noise and emissions standards. As required by Minnesota State law (326B.36 Subd. 5 Duty of Electrical Utility), the Area EPS may require proof of complying with the National Electrical Code before the interconnection is completed, through approval by an electrical inspector recognized by the Minnesota State Board of Electricity. The DER Operator shall maintain the DER facilities using industry standards and best practices in order to reduce the likelihood of an unintended DER operating state causing adverse impacts to customers or the Area EPS.

In the event of an inconsistency between various laws, rules, standards, contracts, or policies over interconnection requirements, the resolution to this inconsistency shall be resolved by assigning an order of precedence from highest to lowest as follows:

1. State of Minnesota statutes
2. Minnesota Public Utilities Commission approved standards, tariffs or orders
3. National Standards, Codes, and Certifications

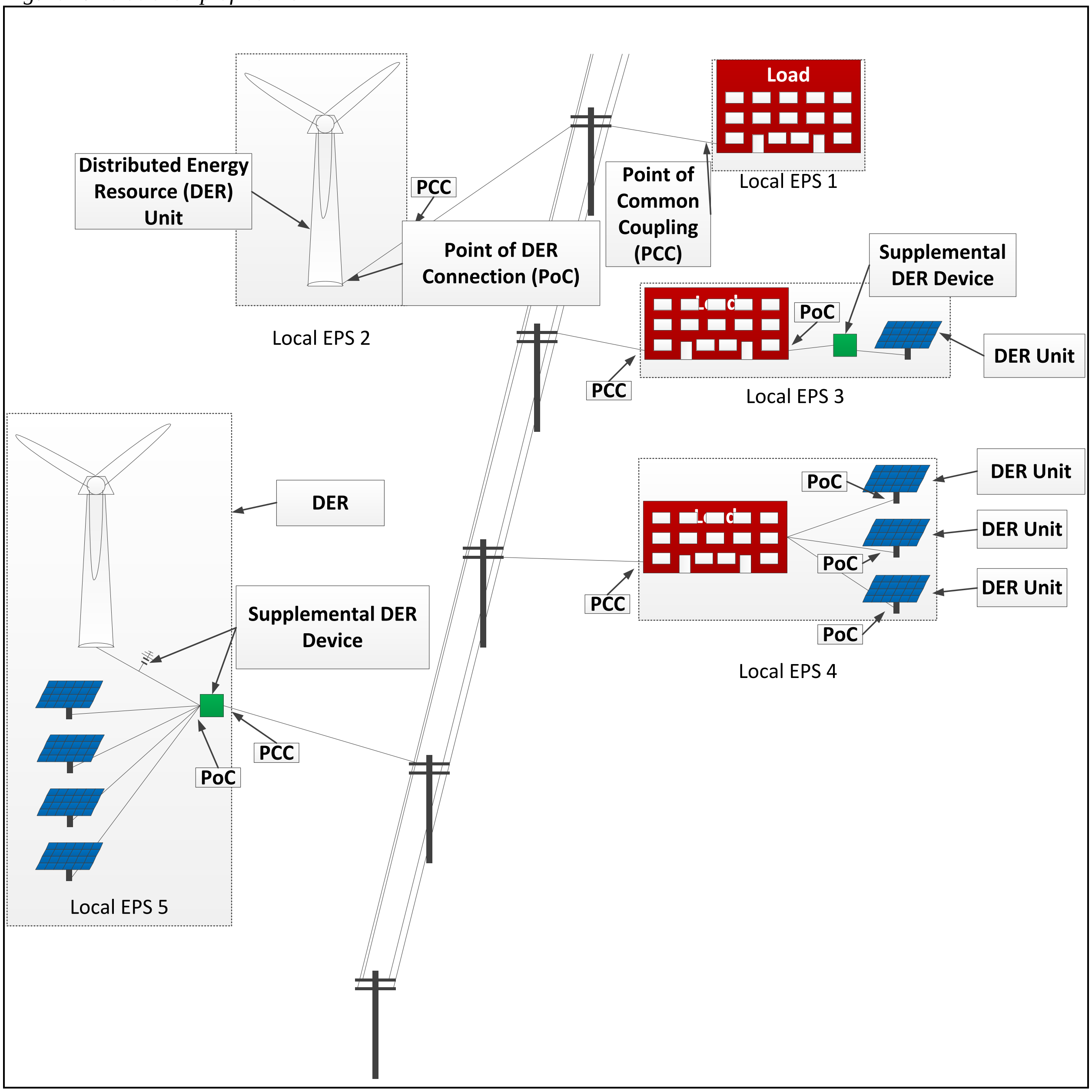
[3] For example, low voltage secondary networks have unique interconnection concerns and the recommended practice in IEEE 1547.6 should be used in conjunction with IEEE 1547 and IEEE 1547.1.

[4] See IEEE 1547 and the TIIR Annex B for further information on the RPA. The RPA is the point at which IEEE 1547 interconnection and interoperability requirements are required to be met.

4. Agreements between the Area EPS Operator and the DER Operator
5. Area EPS Operator published documents

Figure 2 contains a depiction and description of the relationship of some key terms used throughout this document. The usage of these terms as it relates to Figure 2 is consistent with IEEE 1547 definitions. Each of the terms are defined in Section 3-B of this document. Additional discussion of the terms is found in Annex B.

Figure 2. Relationship of Terms



1.2 Scope

The statewide TIIR applies to all DER technology sized at 10 MW and less in AC nameplate capacity[5] that is interconnected at secondary or primary distribution voltages and is operated in parallel[6] with an Area EPS. The TIIR applies to DER for any duration of parallel operation. Non-exporting DER that operate in parallel with the Area EPS are subject to these technical standards.

1.3 Purpose

This TIIR document provides the technical requirements common to all regulated electric utilities in Minnesota for the interconnection and interoperability of DER with associated Area EPS. It provides references and requirements relevant to safety, security, performance, operation, interoperability, testing and verification in harmony with other industry, national and state standards.

1.4 Coordination with Area EPS Operator's Specific Technical Standards

Where this TIIR document does not provide technical guidance, the Interconnection Customer needs to review the Area EPS Operator's specific TSM document, the Area EPS Operator's web site or contact the generation interconnection coordinator at the Area EPS Operator. The following is a brief listing of some of the areas which further technical guidance is to be provided within the Area EPS Operator's TSM.[7]

1) Project Coordination Information
2) Protection system requirements for the DER interconnection
3) Operational standards and requirements
4) DER monitoring and communication requirements
5) Metering requirements in support of specific rates and operational needs

The Area EPS Operator's TSM documents are to be designed to provide utility specific details aligned with the TIIR requirements. The Area EPS Operators' TSM document shall be limited to detailing requirements which are in support of the requirements contained within the TIIR and MN DIP. Additional requirements not contemplated by the TIIR may be mutually agreed upon between the Parties.

At the time this document is being written, IEEE 1547.1 is undergoing a revision which is expected to significantly affect requirements surrounding DER testing and verification. The publication of the updated IEEE 1547.1 standard may necessitate updating this document soon thereafter, most notably addressing changes to Section 12.

[5] The 10 MW AC nameplate capacity limitation is based on Minn. Stat.§ 216B.1611.

[6] National Electric Code and Area EPS specific requirements apply for standby generators and emergency back-up generators with, a break-before-make type of interconnection.

[7] See Annex C for an anticipated list of additional topics in a TSM.

1.5 Convention for Word Usage

Throughout this document, the word *shall* is used to indicate a mandatory requirement. The word *should* is used is used to indicate a recommendation. The word *may* is used to indicate a permissible action. The word *can* is used for statements of capability and possibility.

1.6 Transition Period

All requirements of the TIIR are immediately applicable unless requiring equipment that conforms with IEEE 1547-2018 advanced functionalities.

Area EPS Operators cannot require the use of certified equipment that meets the requirements of IEEE 1547-2018 until such time the equipment is readily available. At such time certified equipment first becomes available, the Area EPS Operator and DER Owner may mutually agree to utilize the certified equipment and functionalities in conformance with the requirements of IEEE 1547-2018. At such time when certified equipment is readily available[8], the entire TIIR shall be applicable.

[8] Refer to UL 1741 for timeline of readily available certified equipment that meets the requirements of IEEE 1547-2018.

2. References

The standards, codes, certification, guides and recommended practices listed in this section are active as of the publication of this document. These standards, codes, certifications, guides and recommended practices may be superseded, withdrawn, or additional applicable revisions may become available after the publication of this document. Later revisions of the technical references listed below may be available and supersede the versions referenced in this document. At the time an interconnection application is submitted, the Area EPS Operator and the DER Operator shall use the most recent applicable technical reference. Application of industry standards, codes, certifications, guides and recommended practices shall be consistent with the standard governing body's manuals, policies, and procedures.

IEC TR 61000-3-7:2008, Electromagnetic compatibility (EMC) - Part 3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.

IEC 61000-4-3:2006+A1:2007+A2:2010, Electromagnetic compatibility (EMC) - Part 4-3: Testing and measurement techniques - Radiated, radio-frequency, electromagnetic field immunity test.

IEC 61000-4-5:2014+A1:2017, Electromagnetic compatibility (EMC) - Part 4-5: Testing and measurement techniques – Surge immunity test.

IEEE Std 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

IEEE Std 1547.1, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

IEEE Std 1547.2, Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE Std 1547.3-2007, Guide for Monitoring Information Exchange and Control of DR Interconnected with Electric Power Systems

IEEE Std 1547.4-2011, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island System with Electric Power Systems

IEEE Std 1547.6-2011, IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks

IEEE Std 1547.7-2013, IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection

IEEE Std 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems

IEEE Std 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installation on Power Systems

IEEE Std 1453.1-2012 (Adoption of IEC/TR 61000-3-7:2008) - IEEE Guide--Adoption of IEC/TR 61000-3-7:2008, Electromagnetic compatibility (EMC)--Limits--Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems

IEEE Std C37.90-2005, IEEE Standard for Relay Systems Associated with Electric Power Apparatus

IEEE Std C37.90.1-2012, IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems Associated with Electric Power Apparatus

IEEE Std C37.90.2-2004, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE C37.95-2014, IEEE Guide for Protective Relaying of Utility-Consumer Interconnections

IEEE Std C50.12-2005, IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above.

IEEE Std C50.13-2014, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above.

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.42-2016, Guide for the Application of Component Surge-Protective Devices for Use in Low-Voltage [Equal to or Less than 1000 V (ac) Or 1200 V (dc)] Circuits

IEEE Std C62.45-2002, IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and Less) AC Power Circuits.

IEEE Std C62.92.2-2017, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II – Grounding of Synchronous Generator Systems

IEEE Std C62.92.6-2017, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Pat VI

IEEE Std 32-1972 (Reaff 1990), IEEE Standard Requirements, Terminology, and Test Procedure for Neutral Grounding Devices

IEEE Std 141-1993, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants – Red Book

IEEE Std 142-2007, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems – Green Book

IEEE Std 242-2001, Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems

IEEE Std 446-1995, Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications

IEEE Std 2030-2011, Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), End-Use Applications, and Loads

IEEE Std 2030.5-2013, IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard.

IEEE Std 1815-2012, IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3)

ANSI C84.1-2016, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

UL 1741, Inverters, Converters, and Controllers for use in Independent Power Systems

ANSI C2-2007, National Electrical Safety Code", Published by the Institute of Electrical and Electronics Engineers, Inc.

NFPA 70, National Electrical Code", Published by the National Fire Protection Association

IEC 61850-7-420:2009, Communication networks and systems for power utility automation - Part 7-420: Basic communication structure - Distributed energy resources logical nodes

IEC 62351-12:2016, Power systems management and associated information exchange - Data and communications security - Part 12: Resilience and security recommendations for power systems with distributed energy resources (DER) cyber-physical systems

3. Definitions and Acronyms

3.1 General

The definitions of terms used in this document are consistent with the IEEE 1547, IEEE 1547.1, and Minnesota DER Interconnection Process definitions, to the extent possible.

The origins of definitions are noted below in Table 1. The associated symbols are shown as a superscript to each term in order to denote the document from which the definition originates. For the purpose of denoting origin, the definition notes are to be considered part of the definition unless otherwise denoted with a separate symbol.

Table 1. Origin of Defined Terms

Document of origin for definition	Symbol
IEEE 1547-2018	x
Minnesota Interconnection Process and Agreement (MN DIP/MN DIA) - 2018	ʌ
Minnesota Statewide Interconnection Technical Standards (TIIR)	ᴦ
Other (additional footnote is shown to denote origin)	ɵ

3.2 Definitions

Abnormal Operating Performance Category[x]: The grouping for a set of requirements that specify technical capabilities and settings for a DER under abnormal operating conditions, i.e., outside the *continuous operation* region.

Area Electric Power System (Area EPS) [^]: The electric power distribution system connected at the Point of Common Coupling

Area Electric Power System Operator (Area EPS Operator) [^]: An entity that owns, controls, or operates the electric power distribution systems that are used for the provision of electric service in Minnesota.

Area EPS Operator Technical Specification Manual (TSM)[r]: The Area EPS Operator's technical manual containing interconnection and interoperability requirements specific to the Area EPS. The TSM is considered part of the Minnesota technical requirements framework.

Affected Systems[^]: Another Area EPS Operator's System, Transmission Owner's Transmission System, or Transmission System connected generation which may be affected by the proposed interconnection.

Authority Governing Interconnection Requirements (AGIR)[x]: A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the Area EPS. This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc. The degree of AGIR involvement will vary in scope of application and level of enforcement across jurisdictional boundaries. This authority may be delegated by the cognizant and responsible entity to the Area EPS operator or *bulk power system* operator.

NOTE—Decisions made by an authority governing interconnection requirements should consider various stakeholder interests, including but not limited to Load Customers, *Area EPS operators*, *DER operators*, and *bulk power system* operator.

Bulk Power System (BPS) [x]: Any electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment.

NOTE [ө] [9] – The usage of BPS in this document is intended to be generally aligned with the NERC definition of bulk electric systems, which includes transmission facilities with rated voltages above 100 kV; generating units with individual nameplate ratings above 25 MVA with a common point of connection a voltage at 100 kV or above; and generating plants with total capacity ratings above 75 MVA with a common point of connection at 100 kV and above. The term Transmission Power System is used to describe the remaining transmission facilities that are rated for voltages less than 100 kV.

Cease to Energize[x]: Cessation of active power delivery under steady state and transient conditions and limitation of reactive power exchange.

[9] The note associated with BPS is intended to be largely aligned with the NERC definition. This is intended to supplement the definition of IEEE 1547 to reduce confusion since the NERC definition is a subset of the IEEE 1547 definition. A new definition, Transmission Power System is introduced in the section to cover the remaining facilities (i.e. < 100 kV transmission lines).

NOTE 1—This may lead to momentary cessation or trip.

NOTE 2—This does not necessarily imply, nor exclude, disconnection, isolation, or a trip.

NOTE 3—Limited reactive power exchange may continue as specified, e.g., through filter banks.

NOTE 4—Energy storage systems are allowed to continue charging but are allowed to cease from actively charging when the maximum state of charge (maximum stored energy) has been achieved.

Certified Equipment[^]: UL 1741 listing is a common form of DER inverter certification. See **Error! Reference source not found.** and Attachment 5: Certification of Distributed Energy Resource Equipment of the MN DIP.

Continuous Operation[x]: Exchange of current between the DER and an EPS within prescribed behavior while connected to the Area EPS and while the applicable voltage and the system frequency is within specified parameters.

Continuous Operation Region[x]: The performance operating region corresponding to *continuous operation.*

Customers[r]: Individuals or entities that own a Local EPS that is connected to the Area EPS with the purpose of purchasing electric power service from the Area EPS Operator

Distributed Energy Resource (DER) [x]: a source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.

NOTE 1—Controllable loads used for demand response are not included in the definition of DER.

NOTE 2[r]—See MN DIP Glossary of Terms or Figure 2 in IEEE 1547-2018.

Distributed Energy Resource Operator (DER Operator) [x]: The entity responsible for operating and maintaining the distributed energy resource.

Distribution Energy Resource Unit (DER Unit) [x]: An individual DER device inside a group of DER that collectively forms a system.

Electric Power System (EPS) [x]: Facilities that deliver electric power to a load.

NOTE [r] —This may include generation units. See MN DIP Glossary of Terms or Figure 2 in IEEE 1547-2018.

Energize[x]: Active power outflow of the DER to an EPS under any conditions (e.g., steady state and transient).

Energy Storage System (ESS)[r] : An electric system that stores active power for later injection into the Local EPS or Area EPS.

ESS Control Mode[Γ]: The function that manages the real and reactive power flow from or to an ESS in response to certain parameters, (such as time, price signals, frequency or external signals, etc.)

Enter Service[x]: Begin operation of the DER with an energized Area EPS.

Intentional Island[x]: A planned electrical island that is capable of being energized by one or more Local EPSs. These (1) have DER(s) and load, (2) have the ability to disconnect from and to parallel with the Area EPS, (3) include one or more Local EPS(s), and (4) are intentionally planned.

NOTE—An intentional island may be an *intentional Area EPS island* or an *intentional Local EPS island* (also: "facility island").

Interconnection[x]: The result of the process of adding DER to an Area EPS, whether directly or via intermediate Local EPS facilities.

Interconnection Agreement[^]: The terms and conditions between the Area EPS Operator and Interconnection Customer (Parties). See MN DIP Section 1.1.5 for when the Uniform Statewide Contract or MN DIA applies.

Interconnection Customer[^]: The person or entity, including the Area EPS Operator, whom will be the owner of the DER that proposes to interconnect a DER(s) with the Area EPS Operator's Distribution System. The Interconnection Customer is responsible for ensuring the DER(s) is designed, operated and maintained in compliance with the Minnesota Technical Requirements.

Interconnection Facilities [^] – The Area EPS Operator's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the DER and the Point of Common Coupling, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the DER to the Area EPS Operator's System. Some examples of Customer Interconnection Facilities include: supplemental DER devices, inverters, and associated wiring and cables up to the Point of DER Connection. Some examples of Area EPS Operator Interconnection Facilities include sole use facilities; such as, line extensions, controls, relays, switches, breakers, transformers and shall not include Distribution Upgrades or Network Upgrades.

Interconnection System[x]: The collection of all interconnection and interoperability equipment and functions, taken as a group, used to interconnect a DER to an Area EPS.

Interface[x]: An electrical or logical connection from one entity to another that supports one or more energy or data flows implemented with one or more power or data links.

Interoperability[x]: The capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively. (IEEE Std 2030)

Inverter[x]: A machine, device, or system that changes direct-current power to alternating-current power.

NOTE[r] - While the classical definition of inverter originating from IEEE 1547 considers power flow in a single direction, the usage of the term in this document indicates potential for bi-directional capabilities. The machine, device, or system can change power from direct-current to alternating-current and the machines, devices, or systems may also have capabilities to change power from alternating-current to direct-current.

Island[x]: A condition in which a portion of an Area EPS is energized solely by one or more Local EPS through the associated PCCs while that portion of the Area EPS is electrically separated from the rest of the Area EPS on all phases to which the DER is connected. When an island exists, the DER energizing the island may be said to be "islanding".

Load[x]: Devices and processes in a local EPS that use electrical energy for utilization, exclusive of devices or processes that store energy but can return some or all of the energy to the local EPS or Area EPS in the future.

Local DER Communication Interface[x]: A local interface capable of communicating to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER.

Local Electric Power System (Local EPS) [x]: An EPS contained entirely within a single premises or group of premises.

Maintenance Requirements [ө]: The maintenance terms and conditions between the Area EPS Operator and Interconnection Customer (Parties) included in the Operating Agreement as Attachment 5 of the Interconnection Agreement.

Material Modifications [^]: A modification to machine data, equipment configuration or to the interconnection site of the DER at any time after receiving notification by the Area EPS Operator of a complete Interconnection Application that has a material impact on the cost, timing, or design of any Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later Queue Position or the safety or reliability of the Area EPS.[10]

[10] A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) changes the physical location of the point of common coupling; such that it is likely to have an impact on technical review; (2) increases the nameplate rating or output characteristics of the Distributed Energy Resource; (3) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (4) changes transformer connection(s) or grounding; and/or (5) changes to a certified inverter with different specifications or different inverter control settings or configuration. A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes the ownership of a Distributed Energy Resource; (2) changes the address of the Distributed Energy Resource, so long as the physical point of common coupling remains the same; (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; and/or (4) increases the DC/AC ratio but does not increase the maximum AC output capability of the Distributed Energy Resource in a way that is likely to have an impact on technical review.

Minnesota DER Interconnection Agreement (MN DIA)[^]: The Minnesota Distributed Energy Resource Interconnection Agreement. See MN DIP Section 1.1.5 for when the Uniform Statewide Contract or MN DIA applies.

Minnesota DER Interconnection Process (MN DIP)[^]: The Minnesota Distributed Energy Resource Interconnection Process which is statewide interconnection standards for regulated utilities.

MN Technical Requirements [^]: The term including all of the DER technical interconnection requirement documents for the state of Minnesota; including: 1) Attachment 2 Distributed Generation Interconnection Requirements established in the Commission's September 28, 2004 Order in E-999/CI-01-1023) until superseded and upon Commission approval of updated Minnesota DER Technical Interconnection and Interoperability Requirements in E-999/CI-16-521.

Momentary Cessation[x]: Temporarily *cease to energize* an EPS, while connected to the Area EPS, in response to a disturbance of the *applicable voltages* or the system frequency, with the capability of immediate Restore Output of operations when the applicable voltages and the system frequency returns to within defined ranges.

Nameplate Ratings[x]: nominal voltage (V), current (A), maximum active power (kW), apparent power (kVA), and reactive power (kvar) at which a DER is capable of sustained operation.

> NOTE—For Local EPS with multiple DER units, the aggregate DER nameplate rating is equal to the sum of all DERs nameplate rating in the Local EPS, not including aggregate capacity limiting mechanisms such as coincidence factors, plant controller limits, etc., that may be applicable for specific cases.

Normal Operating Performance Category[x]: The grouping for a set of requirements that specify technical capabilities and settings for DER under normal operating conditions, i.e., inside the *continuous operation* region.

Non-export, Non-exporting[Γ]: When the DER is sized and designed such that the DER output is used for host load only and is designed and operated to prevent the transfer of electrical energy from the DER to an Area EPS or TPS.

Operating Requirements[^]: Any operating and technical requirements that may be applicable due to the Transmission Provider's technical requirements or Minnesota Technical Requirements, including those set forth in the MN DIA.

Parallel Operation[Γ]: a source operated in parallel with the grid when it is connected to the distribution grid and can supply energy to the customer simultaneously with the Company supply of energy.

Permissive Operation: Operating mode where the DER performs ride-through either in *mandatory operation* or in *momentary cessation*, in response to a disturbance of the *applicable voltages* or the system frequency.

Permissive Operation Region: The performance operating region corresponding to permissive operation.

Point of Common Coupling (PCC)[x]: The point of connection between the Area EPS and the Local EPS.

NOTE 1—See MN DIP Glossary of Terms or Figure 2 in IEEE 1547.

NOTE 2—Equivalent, in most cases, to "service point" as specified in the National Electrical Code™ and the National Electrical Safety Code™.

Point of Distributed Energy Resources Connection (point of DER connection–PoC)[x]: The point where a DER unit is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS.

NOTE 1—See MN DIP Glossary of Terms or Figure 2 in IEEE 1547.

NOTE 2—For (a) DER unit(s) that are not self-sufficient to meet the requirements without (a) supplemental DER device(s), the point of DER connection is the point where the requirements of this standard are met by DER (b) device(s) in conjunction with (c) supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

Power Control[r]: System that controls the output (production or discharging) and input (charging) of one or more DER in order to limit output, input, export and/or import.

Range of Allowable Settings[x]: The range within which settings may be adjusted to values other than the specified default settings.

Reference Point of Applicability (RPA)[x]: The location where the interconnection and interoperability performance requirements specified in this standard apply.

Regional Transmission Operator (RTO)[r]: The functional entity that maintains the real-time operating reliability of the bulk electric power within a reliability coordinator area.

NOTE – This definition is based on the IEEE 1547 regional reliability coordinator definition. In Minnesota, i.e. the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP), perform this function based on territory.

Restore Output[x]: Return operation of the DER to the state prior to the abnormal excursion of voltage or frequency that resulted in a ride-through operation of the DER.

Return to Service[x]: Enter service following recovery from a trip.

Ride-Through[x]: Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

Secondary Network[r]: An AC distribution system where the low-voltage of the distribution transformers are connected to a common network for supplying electricity directly to consumers. There are two types of secondary networks: grid networks and spot networks.

Supplemental DER Device[x]**:** Any equipment that is used to obtain compliance with some or all of the interconnection requirements of this standard.

NOTE—Examples include capacitor banks, STATCOMs, harmonic filters that are not part of a DER unit, protection devices, plant controllers, etc.

Technical Interconnection and Interoperability Requirements (TIIR)[r]**:** The supplemental set of DER interconnection and interoperability requirements in this document which together with each Area EPS Operator's Technical Specification Manual (TSM) and industry interconnection standards, make up the Minnesota Technical Requirements.

Technical Specification Manual (TSM) [r]**:** The Area EPS Operator specific interconnection and interoperability requirements for interconnection of Distributed Energy Resources which together with the Technical Interconnection and Interoperability Requirements (TIIR) and industry interconnection standards, make up the Minnesota Technical Requirements.

Transmission Power System[r] **(TPS):** Any transmission or generation facility that is not part of the bulk power system.

NOTE - In general, this is transmission facilities rated at voltages less than 100 kV; transmission generation units with power ratings less 25 MVA; and generation plants with total capacity ratings less than 75 MVA.

Trip[x]**:** Inhibition of immediate return to service, which may involve disconnection.

NOTE—Trip executes or is subsequent to cessation of energization.

Type Test[x]: a test of one or more devices manufactured to a certain design to demonstrate, or provide information that can be used to verify, that the design meets the requirements specified in this standard.

3.3 Acronyms

AGIR	Authority Governing Interconnection Requirements
BPS	Bulk Power System
DER	Distributed Energy Resource
EPS	Electric Power System
ESS	Energy Storage System
MN DIA	Minnesota Distributed Energy Resource Interconnection Agreement
MN DIP	Minnesota Distributed Energy Resource Interconnection Process
PoC	Point of Distributed Energy Resource Connection

PCC	Point of Common Coupling
RPA	Reference Point of Applicability
RTO	Regional Transmission Operator
TIIR	Technical Interconnection and Interoperability Requirements (this standard document)
TPS	Transmission Power System
TSM	Technical Specifications Manual (supplemental Area EPS Operator document)

4. Performance Categories

4.1 Introduction

The IEEE 1547 standard provides a technology-neutral approach in which performance categories are assigned to specify required capability for reactive power performance, voltage regulation performance, and response to abnormal conditions. Performance categories describe minimum equipment capability and the required ranges of allowable settings. The next two subsections, Performance Category Assignment and Use of Default Parameters, contain the Minnesota specific application requirements based on the available performance categories defined in IEEE 1547 standard.

There are a number of available performance categories defined in IEEE 1547 standard which contemplates current and future system needs at varying levels of DER penetration. Performance requirements associated with performance categories could be driven by Area EPS, TPS or BPS needs. Regional coordination and standardization in selection of abnormal performance categories is necessary. The entity determining the appropriate performance categories is specified by the IEEE 1547 standard. The subsections below contain the specific requirements that have been determined to be appropriate for application in Minnesota.

Category A and B specify reactive power capability and voltage regulation performance requirements. Category B is intended for use where DER penetration is higher and where the DER power output is subject to frequent large variations. Category B encompasses all of Category A capabilities. Category A and B assignment is specified by the Area EPS Operator, Section 4.2.A.

Categories I, II, and III differentiate performance requirements for DER response to abnormal conditions. The Minnesota Public Utilities Commission is delegated authority by the IEEE 1547 standard to provide guidance for assigning abnormal performance categories which is specified in Section 4.2.B. Category III is the highest capability and can inherently meet the ride-through requirements of the lower categories. In contrast, the voltage and frequency trip requirements of higher categories may not be met by lower categories as the range of allowable settings may be mutually exclusive.

I. Category I encompasses minimum BPS essential needs
II. Category II coordinates with North American Electrical Reliability Corporation (NERC) PRC-024-2 with a modification to the voltage ride-through in order to account for characteristics of distribution load devices[11].
III. Category III covers all BPS reliability needs and also introduces ride-through requirements aimed at addressing high DER penetration integration issues such as power quality events and other abnormal system conditions which may arise from DER tripping in the Local EPS.

4.2 Performance Category Assignment

Performance Category assignment is specific to the state of Minnesota. Based on IEEE 1547, the Area EPS Operator assigns normal performance categories - Category A and B, as shown in Section 4.2.A. The Minnesota Public Utilities Commission assigns abnormal Categories I, II, and III, as shown in Section 4.2.B. The process of assigning performance categories considers Area EPS needs; as well as TPS and BPS needs on a regional and wider basis.

A. Normal – Category A and B

Considering existing[12] and future high penetration DER conditions, and the example decision tree in Annex B of IEEE 1547, the assignment of the category for reactive power capabilities and voltage regulation performance of DER in Minnesota shall be as follows:

Table 2. Normal Performance Category Assignment

Technology	Normal performance category
Inverter-based DER	Category B
Synchronous machine generation	Category A

The above assignment of Categories A and B is expected to cover the vast majority of interconnections. Any instances that do not fall within the above assignment shall be:

1) reviewed on a case-by-case basis, with the Area EPS Operator making determination[13] for requiring Category A or B; or
2) performance category assignments specified in the Area EPS Operator's TSM

B. Abnormal – Categories I, II, and III

The abnormal performance category assignment should also consider a future level of DER penetration that could impact the TPS or BPS if not properly coordinated. The

[11] Fault Induced Delayed Voltage Recovery is the main load consideration. This situation arises where distribution loads that typically consume reactive power draw increased levels of reactive power due to a low voltage event. The additional reactive power consumption of the distribution loads leads to a slower rebound in voltage returning to nominal levels.
[12] At the time this document is being written, portions of the Area EPS in Minnesota are exhibiting power flow characteristics of a high penetration DER environment. Based on these localized pockets of high penetration at the Area EPS level, a future with high penetration at the Area EPS, TPS, and BPS is considered when assigning performance categories in Minnesota.
[13] The Area EPS Operator should consider Annex B of IEEE 1547 when making these determinations on a case-by-case basis or in TSM requirements.

Area EPS Operators in the state of Minnesota shall constructively work with the Regional Transmission Operator to provide a recommendation whether Category II or Category III is the proper default category assignment for inverter-based DER. The decision shall balance the needs of the Area EPS and Local EPS with TPS and BPS considerations. Until a decision is made by the Regional Transmission Operator within that region, all synchronous machine DER shall be assigned Category I and all inverter-based DER shall be assigned Category II. Any instances that do not fall within the above assignment shall:

1) be reviewed on a case-by-case basis, with the Area EPS Operator making determination[14] for requiring Category I, II or III; or
2) have performance category assignment specified in the Area EPS Operators TSM.

4.3 Use of Default Parameters

The DER shall use the IEEE 1547 default parameter settings for all capabilities and performance requirements of the applicable performance category unless otherwise specified by the TIIR or Area EPS Operator's TSM. In order to protect BPS and TPS reliability and to produce a response from DER that can be modeled, deviating from the statewide default parameters for abnormal performance category settings should be a rare occurrence.

4.4 Assignment of Alternative Abnormal Operating Performance Category

Normal Operating Performance Category assignments are shown in Section 4.2.A in this document. Abnormal Operating Performance Category assignments may be reviewed on a case-by-case basis, with the Area EPS Operator making determination for requiring Category A or B or listed in the Area EPS Operator's TSM.

Upon mutual agreement, provided no adverse effects are caused to the distribution system, TPS or BPS, exceptions may be made for Categories I, II and III if the DER technology is not able to meet the assignment outline in Section 4.2.B. This should be a rare occurrence. Should the DER technology readily exist to meet the stated assignments in Section 4.2.B, no exception shall be allowed.

5. Reactive Power Capability and Voltage/Power Control Performance

5.1 Introduction

A widely observed effect of relatively high levels of DER is reverse power flow causing an elevation of voltage near the DER source. The Area EPS Operator is responsible for maintaining voltage within standard ANSI C84.1 Range A for normal operations. Depending on the Area EPS characteristics for the system serving the location of interconnection, an economic solution to mitigate high-voltage caused by DER may be to implement DER active power and reactive power control functions. The implementation of these functions can

[14] The Area EPS Operator should consider Annex B of IEEE 1547 when making these determinations on a case-by-case basis or in TSM requirements.

contribute to an Area EPS Operator's ability to operate the system in a safe and reliable manner as increasing levels of DER are deployed. The use of these functions can allow higher levels of DER deployment in an economic manner. In general, reactive power control functions should be used to control voltage[15] for normal Area EPS conditions, by injecting or absorbing vars. The voltage-active power control function should be used for abnormal Area EPS conditions (for example temporary feeder configuration) which work by reducing active power output in order to reduce the severity or alleviate the high voltage condition.

5.2 General

As defined by IEEE 1547, DER reactive power capability, required by the applicable performance category[16], shall be available for use by the Area EPS Operator for the purpose of mitigating impacts of DER on the Area EPS. The real and reactive power capabilities shall be available for implementation to resolve DER grid impacts after the initial installation, even if functions are not initially implemented. The Area EPS Operator shall notify the DER Operator when a change in reactive power control modes is required to address Area EPS operating needs. Any implementation of functions shall adhere to applicable agreements.

The decision to use reactive power control functions can affect transmission power system reactive power flow patterns. TPS and BPS impacts should be considered by the Area EPS Operator when specifying reactive power control strategies in the Area EPS Operator's TSM.

The Area EPS Operator shall specify the control mode and settings for the DER. The DER Operator shall implement the settings in a reasonable timeframe. When a communication channel exists from the Area EPS Operator's communication interface to the Local DER Communication Interface, the Area EPS Operator shall have the right to adjust the settings remotely in conformance with the Interconnection Agreement. If no communication channel exists, the DER Operator shall update settings and implement the changes within the time frame required by the Area EPS Operator once receiving the change request per the Area EPS Operator's established protocol defined in agreements or within the protocol defined in the Area EPS Operator's TSM. The timeframe required for the DER Operator to update settings and implement changes should not be shorter than three (3) Business Days. The type of settings change and the impact to the operation of the Area EPS should be considered in determining appropriate time for implementing settings. Failure to carry out a settings change within the applicable timeframe requested by the Area EPS Operator, may result in temporary disconnection of the DER if the inability to make the adjustment may affect safety, reliability or service quality. Nothing in this section precludes the Area EPS Operator's ability to immediately temporarily disconnect the DER for urgent operational needs at any time.

[15] The effectiveness of using reactive power control functions depends on the technical characteristics of the system including the send-out voltage, total line impedance, and X/R ratio.

[16] Categories A and B have different reactive power capability requirements, both require a percentage of the apparent power nameplate rating to be available for reactive power. Category B is capable of injecting or absorbing 44% of apparent power rating when active power output exceeds 20% of DER nameplate rating. Category A is capable of reactive power injection of 44% and absorption of 25% of nameplate apparent power when active power output exceeds 20% of DER nameplate rating. Both categories' reactive power requirements contain a gradient between 5% and 20% active power output levels. See section 5.2 of IEEE 1547 for additional details.

5.3 Voltage and Reactive Power Control

As defined by IEEE 1547 Clause 5.3.1, the Area EPS Operator specifies a reactive power control mode. Unless otherwise specified in the Area EPS Operator's TSM or specified in the Interconnection Agreement, the DER shall be installed with constant power factor mode enabled with 0.98 power factor, absorbing reactive power.

5.4 Voltage and Active Power Control (volt-watt)

Unless otherwise specified by the Area EPS Operator's TSM or in the Interconnection Agreement, the DER shall operate with the voltage-active power function enabled with the following default settings[17].

Table 3. Voltage-Active Power Setting for Category A and Category B DER

Voltage-Active Power Parameters	Default Setting
V_1	1.06 V_n
P_1	P_{rated}
V_2	1.1 V_n
P_2 (applicable to DER that can only generate active power)	The lesser of 0.2 P_{rated} or P_{min}[a]
P'_2 (applicable to DER that can generate and absorb active power	0[b]
Open Loop Response Times	10 s[c]

[a] P_{min} is the minimum active power output in p.u. of the DER rating.

[b] P'_{rated} is the maximum amount of active power that can be absorbed by the DER. ESS operating in the negative real power half plane, through charging, shall follow this curve as long as available energy storage capacity permits this operation.

[c] Any setting for the open loop response time of less than 3 seconds shall be approved by the Area EPS Operator with due consideration of system dynamic oscillatory behavior.

The voltage-active power function may reduce DER energy production during times of abnormally high voltage. The extent of that reduction of production is dependent on the specific setting of the function, as well as actual steady-state voltage observed over time at the DER location. Deviation in the voltage parameters settings from the default, such as setting a voltage parameter to a lower value, may exacerbate the possible energy production reduction.

In the circumstance where a DER Operator's production is being impacted by the Area EPS voltage, the DER Operator should notify the Area EPS Operator of the voltage concern[18]. The Area EPS Operator shall investigate the cause of abnormal voltage. If the abnormal voltage is

[17] The default IEEE 1547 volt-watt default setting will not begin curtailing real power until the voltage is beyond 1.06 per unit voltage, which is the upper end of the range of normal voltages allowed under ANSI C84.1.

[18] For example, DER with the PCC located near the substation with a high source voltage may require upward adjustment of the V_1 parameter to avoid significant production impacts.

originating from the Area EPS, the Area EPS Operator may need to modify equipment or settings. The Area EPS Operator may also need to work with other electric services to bring voltage within ANSI C84.1 Range A. If the abnormal voltage is originating from the DER Operator's premise, the DER Operator is responsible for mitigating the root cause.[19]

The default in IEEE 1547 is to disable voltage-active power function. The TIIR requirement may necessitate a settings change from the default settings that DER equipment may contain when shipped from a manufacturer.

6. Response to Abnormal Conditions

6.1 Introduction

Abnormal conditions can arise on the Area EPS, TPS or BPS, for which the DER shall appropriately respond based on the performance category assigned, required settings, and the requirements in IEEE 1547. The abnormal performance capabilities are intended to support wide area and localized system stability. The Minnesota statewide default parameters for DER response to abnormal conditions shall not materially impact safety, reliability, or the Area EPS Operator's ability to operate the Area EPS.[20]

6.2 Voltage Ride-Through and Tripping

The DER shall conform to the ride-through requirements for the applicable Abnormal Operating Performance Category. The IEEE 1547 default parameters shall be implemented by the DER Operator for the applicable performance category, unless otherwise specified by the Area EPS Operator's TSM. The RTO may provide guidance on mandatory ride-through capabilities.

Until the Regional Transmission Operator determines the setting for mandatory tripping, the Table 4 and Table 5 shall be used.

[19] All parties should attempt, with a good-faith effort, to resolve voltage concerns in the process identified in TIIR Section 5.3. Any voltage concern disputes not resolved are to follow the dispute resolution process in MN DIP Section 5.3 and MN DIA Article 10.

[20] The Area EPS Operators of Minnesota strive to be included in any efforts by the appropriate entities' Independent System Operator seeking to impose default parameter values on DER that differ from IEEE 1547. The process of determining new statewide or regional abnormal response parameter defaults that deviate from national standard default values should only be the outcome of a broad consensus process.

Table 4. DER Response (shall trip) to Abnormal Voltages for DER of Abnormal Operating Performance Category I

Shall Trip – Category I		
Shall Trip Function	Default Setting[a]	
	Clearing time (s)	Voltage (p.u. of nominal voltage)
UV2	0.16	0.45
UV1	2.0	0.7
OV1	2.0	1.10
OV2	0.16	1.20

Table 5. DER Response (shall trip) to Abnormal Voltages for DER of Abnormal Operating performance Category II

Shall Trip – Category II		
Shall Trip Function	Default Setting[a]	
	Clearing time (s)	Voltage (p.u. of nominal voltage)
UV2	0.16	0.45
UV1	10.0	0.70
OV1	2.0	1.10
OV2	0.16	1.20

Notes for Table 4 and 5

[a]The Area EPS Operator may specify other voltages and clearing time trip settings within the range of allowable settings, e.g. to consider Area EPS protection schemes.

A. Modifications to the Permissive Operating Capability Region

Momentary Cessation may be required for a portion of the Permissive Operating Capability Region. Consult the Area EPS Operator's TSM for further details.

6.3 Frequency Ride-Through and Tripping

The DER shall conform to the ride-through requirements for the applicable Abnormal Operating Performance Category. The IEEE 1547 default parameters shall be implemented by the DER Operator for the applicable performance category. The RTO may provide guidance on mandatory ride-through capabilities.

Until the RTO provides guidance the settings for mandatory tripping, Table 6 shall be followed.

Table 6. DER Response (shall trip) to Abnormal Frequencies for DER of Abnormal Operating Performance Category I, Category II and Category III

Shall Trip Function	Default Setting[a]	
	Clearing time (s)	Frequency (Hz)
UF2	0.16	56.5
UF1	300.0	58.5
OF1	300.0	61.2
OF2	0.16	62.0

Notes for Table 6
[a]The frequency and clearing time set points shall be field adjustable. The actual applied under-frequency (UF) and over-frequency (OF) trip settings shall be specified by the Area EPS Operator in coordination with the requirements of the regional reliability coordinator. If the Area EPS Operator does not specify any settings, the default settings shall be used.

The DER shall conform to the Rate of Change of Frequency (ROCOF) ride-through requirements for the applicable Abnormal Operating Performance Categories. The IEEE 1547 values shown in Table 7 shall be implemented by the DER Operator for the applicable performance category.

Table 7. Rate of Change Frequency (ROCOF) Ride-Through Requirements for DER of Abnormal Operating Performance Category I and Category II

Category I	**Category II**
0.5 Hz/s	2.0 Hz/s

The DER shall conform to the frequency-droop requirements for the applicable Abnormal Operating Performance Categories. The IEEE 1547 values shown in Table 8 shall be implemented by the DER Operator for the applicable performance category.

Table 8. Parameters of Frequency-Droop (Frequency-Power) Operation for Abnormal Operating Performance Category I and Category II

Parameter	**Default Settings[a]**	
	Category I	**Category II**
k_{OF}, k_{UF}	0.05	0.05
$T_{response\ (small\ signal)}$ (s)	5	5
db_{OF}, db_{UF} (Hz)	0.036	0.036

Notes for Table 8
[a]Adjustments shall be permitted in coordination with the Area EPS operator.

6.4 Exceptions

Tripping or intentional islanding as an alternative to ride-through is allowed in specific situations (such as when a large load is on premise) which may modify the DER response to abnormal conditions. Refer to IEEE 1547 Section 6.4.2.1 and 6.5.2.1 for additional details.

DER systems designated by authority having jurisdiction as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by applicable industry code, shall be exempt from the ride-through requirements of this section.

6.5 Dynamic Voltage Support

Dynamic voltage support may be required. Consult the Area EPS Operator's TSM for further details.

7. Protection Requirements

7.1 Introduction

The DER shall be designed with proper protective devices to respond to faults and abnormal conditions in accordance with applicable standards including IEEE 1547 and parameters defined by this document or the Area EPS Operator's TSM.

7.2 Requirements

Details of each Area EPS Operator's protection requirements shall be found in the Area EPS Operator's TSM. As specified by Area EPS Operator's TSM, an AC disconnect furnished by the DER Operator may be required for Area EPS Operator's personnel to safely isolate the DER from the Area EPS. If required, the AC disconnect shall provide a visible air-gap, shall be lockable, and accessible to Area EPS Operator's personnel to safely isolate the DER from the Area EPS.[21]

All equipment providing relay functions shall meet or exceed ANSI/IEEE Standards for protective relays, or standards applicable for the installation voltage, unless otherwise specified by the Area EPS Operator's TSM.[22] Other requirements associated with protection and instrument transformer application may be specified by the Area EPS Operator.

7.3 Response to Faults and Open Phase Conditions

The DER shall Cease to Energize and Trip for faults on the Area EPS. The DER shall detect and Cease to Energize and Trip all phases to which the DER is connected for an open phase condition occurring directly at the reference point of applicability. The requirement to Cease to Energize for a single-phase condition shall apply to both three-phase inverters and three-phase installations made up of single-phase inverters. As required by IEEE 1547, the DER shall detect and Cease to Energize and Trip for unintentional islands. When restoring output after Momentary Cessation, the Restore Output settings of the DER shall be coordinated with the Area EPS reclosing timing.

7.4 Additional Protection

Additional protection may be required as part of the Area EPS's Interconnection Facilities to limit Area EPS exposure to reliability impacts.[23] Other circumstances, such as low voltage secondary network interconnections, may require additional protection associated with the Area EPS's Interconnection Facilities.

In general, an increased degree of protection is required for increased DER size. Medium and large DER installations may require more sensitive and faster protection to minimize

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[21] In some cases, the NEC required device for rapid shutdown for inverter-based DER may meet the Area EPS Operator's requirement for an AC disconnect if it provides a visual air-gap.

[22] Inverters certified to UL 1741 may contain protective functions that do not require equivalent external protective relays to meet IEEE 1547 requirements.

[23] For example, additional layers of protection may be required if the Area EPS's Interconnection Facilities lead to significant line exposure.

potential damage and ensure safety.[24] The addition of a new DER in conjunction with the aggregate of the existing DER systems may also affect the ability of existing protection schemes to function, which may require modification to the Area EPS's protection equipment.

8. Metering

8.1 Introduction

The Area EPS Operator shall specify metering requirements in the Area EPS Operator's TSM. Information about the DER's present and historic operating characteristics may be required by the Area EPS Operator in order to plan and operate the system. In addition, information may be needed to fulfill financial and regulatory obligations associated with DER energy production.

The different types of data may have different requirements in terms of accuracy and granularity, which should be considered by the Area EPS Operator. The information required for a given DER size may change as DER penetration increases on a portion of the Area EPS. Furthermore, each utility uses different metering technology that changes over time, each with its own integration considerations. Defining static metering requirements is a challenge. It is beyond the scope of this document to describe all of the potential different metering configurations or requirements. In general, the Area EPS Operator shall consider the following types of information when developing metering requirements in its TSM:

i. Operational – near-real-time information on the DER operating characteristics can be needed in order to perform certain actions such as reconfiguring a feeder or restoring a feeder after an outage.
ii. Planning – an archive of time-series information over multiple years of DER operation is required for Area EPS, BPS and TPS planning.
iii. Regulatory – The Area EPS Operator may have obligations to track and report on the amount of energy produced from renewable energy DER[25]. Specific incentive programs or tariffs can create additional metering needs.
iv. Billing – the Area EPS Operator is responsible for accounting for energy transactions with the DER Operator and shall have access to revenue grade metering information.

The Area EPS Operator may require separate accounting of generation and load power injection and consumption characteristics in order to meet planning and operating objectives on the Area EPS and TPS. Correlation of time data may be necessary in certain situations[26] and the Area EPS Operator should consider this factor when specifying metering requirements in its TSM. The Area EPS Operator may use other means of collecting the necessary information, besides the meter, if the Area EPS Operator determines the information is adequate for the intended use based on industry standards and best practices.

[24] Ride-through capabilities for bulk power system support should be considered before setting protective tripping times that conflict with BPS support.

[25] Renewable energy credits for certain Area EPS Operator tariffs is an example of reasons to track energy production.

[26] For example, where a time of use tariff exists and multiple meters are present, the time intervals of meters need to be time synchronized in order for the Area EPS Operator to properly execute its tariffed obligations. Another example would be a planning need where data has to be synchronized in time.

8.2 Requirements

The DER installation shall include metering provisions based on the interconnection characteristics and requirements. Each Area EPS Operator shall specify requirements in their TSM.

9. Interoperability

9.1 Introduction

The IEEE 1547 standard requires the capability to provide a Local DER Communication Interface, which is the basis for interoperability requirements. The Local DER Communication Interface may be used to exchange standardized information with the Area EPS Operator. The exchange of information allows the Area EPS Operator to perform monitoring and control functions necessary to the safe and reliable operation of the Area EPS.

Per IEEE 1547 Section 10.1, the decision to use the Local DER Communication Interface or to deploy a communications network is determined by the Area EPS Operator. Given existing and future DER integration needs, as well as the differences amongst various Area EPS Operator's systems, no uniform set of standards is defined in this document for requiring use of the Local DER Communication Interface. The factors included in an Area EPS Operator's decision to use the Local DER Communication Interface shall be provided in the Area EPS Operator's TSM.

For DER where a standard Local DER Communication Interface is not used upon initial installation, future Area EPS, TPS, or BPS conditions may arise that trigger a need to begin using the Local DER Communication Interface. The DER Operator shall constructively participate in evaluating feasibility of establishing use of the Local DER Communication Interface if needed due to considerations for integrating DER with an Area EPS. Any modifications to utilize the Local DER Communication Interface for existing interconnected DER systems shall be established by mutual agreement between the Area EPS Operator and the DER Operator.

DER systems designated by authority having jurisdiction as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by applicable industry code, may be exempt from the interoperability requirements of this section. Additional details are listed in the Area EPS Operator TSM.[27]

9.2 Monitoring, Control and Information Exchange

When information exchange through the Local DER Communication Interface is required by the Area EPS Operator, the IEEE 1547 interoperability parameters shall be available for use. The Area EPS Operator shall have read access to all parameters in the nameplate information and monitoring information. The Area EPS Operator shall have read and write access to all parameters in configuration information and management information. The Area EPS

[27] IEEE 1547 does allow exemption in capabilities that the Area EPS operator may require in certain situation.

Operator may choose to use a subset of the available parameters in order to meet operating objectives of safe, reliable, and quality electric service. Writing of information by the Area EPS Operator through the Local DER Communication Interface, shall follow agreements governing Area EPS Operator control of the DER operating state control modes and parameters.

When the Local DER Communication Interface is required by the Area EPS, the Area EPS shall have access to read and write parameters shown in the sub clauses associated with IEEE 1547, Section 4.6 – *Control capability requirements* – including capability to disable permit to service; capability to limit active power; and execution of mode and parameter changes.

9.3 Communications

When communication is required to the DER and/or the applicable meter(s), the DER Operator may be responsible for furnishing the communication channel from the Area EPS Operator's applicable system(s) to the DER and/or the meters. The form of communication (Cellular, Radio, etc.) shall be determined by the Area EPS Operator. Additional details of communication requirements shall be specified in the Area EPS Operator's TSM. Communication performance requirements, such as latency of exchanged information, periodicity, reliability of communication channels, and volumes of data, may be defined by the Area EPS Operator's TSM or in an operating agreement.

9.4 Cyber Security

The local physical and network security requirements specified by the Area EPS Operator shall be implemented by the DER Operator. The Area EPS should consider the degree of risk associated with various DER technology and application in determining the cyber security requirements. The Area EPS Operator shall outline cyber security requirement with respect to DER in its TSM.

Communications circuits tied to monitoring and control systems associated with Area Electric Power System (EPS) real-time operations shall meet security and reliability requirements as defined by the Area EPS Operator, industry standards, and appropriate regulating authorities.

A. DER Physical and Front Panel Security

The DER Operator shall provide a reasonable level of security for the DER controls and devices from operation by intruders. The Area EPS Operator may specify additional physical security requirements in its TSM.

B. DER Network Security

The network security requirements and implementation details may differ among Area EPS Operators and are expected to evolve over time in order to maintain cyber security in an environment of constantly changing cyber threats. The network security requirements for the DER Operator may be described in each Area EPS Operator's TSM.

C. Local DER Communication Interface Security

When information is exchanged through the Local DER Communication Interface, consideration should be given to protect access to information. Numerous system architecture approaches and technologies exist for securing the interface. The Area EPS Operator may specify security requirements associated with the Local DER Communication Interface. Where practical, test and verification procedures shall be specified for local DER communication interface security.

10. Energy Storage

10.1 Introduction

An Energy Storage System (ESS) operated in parallel with the Area EPS is a DER subject to the standard applicable reviews and requirements for a DER acting as a generation source (ESS discharging). Additional review is required for unique features of ESS, when compared to other DER, such as the load (ESS charging) aspects and ESS Control Mode(s). The Area EPS Operator should perform the appropriate technical review and study of all aspects of ESS during the appropriate step in the Minnesota Interconnection Process. Power Control characteristics may simplify the review process, since ESS is often inverter-based and ongoing reverse power flow may not be anticipated, but a standard review shall be completed since the potential exists for voltage, thermal, and protection impacts.

Interconnection of ESS in a parallel configuration often requires consideration of compatibility with applicable tariffs. ESS interconnection or operational requirements may result from a customer's choice of DER tariff[28] or load service tariff.

Application of the Minnesota DER TIIR shall not constrain adoption of national standards and best practices as they are developed. The ESS-specific aspects of DER interconnection standards are expected to receive an increased focus from industry standards associations in upcoming years[29], with resulting ESS standards publications at a quicker pace.

The absence of guidance on ESS best practices and standards at a national level makes it likely that this section will require future revision sooner than other sections in the document. The intent of this document is to adopt standards as they become available. The approach taken for ESS in the TIIR is to define functional requirements, leaving implementation, testing, and verification for definition in individual Area EPS Operator's TSM. As was the case with inverter-based DER prior to IEEE 1547 in 2003, the types and use cases associated with ESS will continue to rapidly shift until standards and certifications are developed. Based on these factors, the Area EPS Operator shall specify any additional ESS requirements in the Area EPS Operator's TSM.

[28] For example, a tariff rate associated with a Qualifying Facility (QF), as defined in federal law and often relied upon in net metering rate definitions of eligible energy resources, requires all energy exported to the Area EPS to be from a QF. For ESS to be considered a QF, all of the energy charging ESS must originate from a different DER which meets the QF definition.

[29] At the time the TIIR are being written, certifications, national standards, guides, and recommended practices governing the capabilities and performance of ESS are yet to be written or published.

10.2 ESS Control Modes

Changes in ESS Control Modes to a mode that was not proposed and reviewed during the interconnection process can result in tariff violations or cause adverse technical impacts to the Area EPS. ESS Control Modes may not necessarily be considered a Material Modification, however the Interconnection Customer shall notify the Area EPS Operator of an unapproved ESS Control Mode prior to the change being implemented. The Area EPS Operator shall discuss with the Interconnection Customer the need, or lack thereof, to review the proposed ESS Control Mode for safety, power quality or reliability reasons.

IEEE 1547 states that a functional software or firmware change may result in another verification process at that time of interconnection and interoperability requirements. The IEEE 1547 standard, and other national standards and certifications, are currently silent on requirements relating to ESS Control Mode definition, implementation (i.e. default responses and ranges of allowable settings), transition between modes, adding new modes after initial interconnection, and all associated testing and verification procedures. Until industry standards and certifications are developed to address these aspects of ESS, a significant gap exists for which a grouping of partial solutions may be required by the Area EPS Operator, including, but not limited to the following requirements:

i. Documenting at the time of application the ESS Control Modes being applied for by the ESS owner. This information may be collected through an Area EPS Operator specific document[30] or the Area EPS Operator's online application portal.
ii. Documenting at the time of application the charge/discharge profile(s) or use case(s) intended to be utilized by the ESS owner. This information may be collected through an Area EPS Operator specific document or the Area EPS Operator's online application portal.
iii. The ESS Control Mode(s) reviewed and approved should be documented in an Operating Agreement. The Operating Agreement should also list the ESS Control Mode(s) that is being utilized. Area EPS Operator shall be notified of changes to ESS Control Mode(s). The changes and notification to the Area EPS Operator shall follow all applicable agreements and requirements as documented in the TSM.
iv. A method of ESS Control Modes security shall be furnished by the DER Operator to assure only ESS Control Modes applied for and reviewed by the Area EPS Operator are used. The security may be in the form of password protection of the functions or other methods specified by the Area EPS Operator's TSM.
v. Operation of the ESS shall be compatible with applicable tariffs[31], as required by the Area EPS Operator standard implementation of the tariffs.
vi. The Area EPS Operator may initiate verification of the ESS operation after the interconnection is complete if information is available indicating the ESS is not functioning as designed or approved.

[30] Upon publication of standards and certifications, this type of information will be well-suited to be included in statewide interconnection process documentation. Until that time, it is likely the type of ESS information needed could rapidly shift, depending on customer preferences and available technology. Continual shifts in technology, application of technology, and market place are occurring at a rapid pace at the time the TIIR is being written.

[31] Definitions of non-exporting and inadvertent export in statewide standards clarifies implementation of certain tariffs for ESS.

10.3 ESS Load Aspects

The load impacts of ESS shall be considered in scope for the statewide TIIR. The load aspects of ESS are not in scope of the IEEE 1547 standard, but reviewing the load aspects in conjunction with generation aspects is crucial to evaluating impacts to the Area EPS and leads to a more efficient review of the overall system. Impacts from ESS may contribute to requirements and mitigations, including but not limited to: electrical component upgrades; information exchange through use of the Local DER Communication Interface; or protection and control system upgrades.

Any Area EPS Operator's operating characteristics requirements for ESS charging operations shall not be more restrictive than the operating characteristics requirements of other comparable loads, to the extent practical or upon mutual agreement. The maximum charge rate of the ESS shall be included in materials submitted to the Area EPS Operator during the technical review portion of the interconnection process.

Certain grid events[32] may cause a large number of ESS in the affected area to simultaneous respond. Any future changes to wholesale markets allowing ESS to participate could also introduce unintentional wide-area ESS simultaneous response and impacts not accounted for during the interconnection process. Interconnection reviews typically do not contemplate this type of group response. The Area EPS Operator may define in the TSM interconnection technical requirements to address impacts from conditions where multiple unrelated ESS on a portion of the Area EPS are operating in concert.

11. Power Control Limiting – Capacity, Export, and Import

11.1 Introduction

The DER Operator may choose to limit the AC capacity of a DER system using Power Controls. Power Controls may also be used to limit DER system export levels to the Local EPS and/or the Area EPS. There are many possible reasons for implementing Power Controls, including meeting specific tariff terms or to mitigate the maximum level of power which can flow on the Local or Area EPS.

These capabilities are referred to as Power Control limited capacity, Power Control limited export, and Power Control limited import. These terms are discussed in the following sections and may be generally referred to as Power Control limiting. Power Control limiting may be accomplished using a Power Control limiting system. An alternate option, specifically related to assurance that the DER does not export power (non-export) to the Area EPS, is to implement the limit through relaying or by sizing DER in relationship to the size of the Local EPS load. The use and method for Power Control limiting shall require approval from the Area EPS Operator[33].

[32] For example, an extended outage could cause all the impacted ESS charge to largely deplete, which could trigger charging of all the effected ESS when power is restored on the Area EPS. The resulting charging could result in unanticipated overloads on the Area EPS unless the condition has been studied.

[33] MN DIP Section 5.14.3 states "the Interconnection Customer must obtain the Area EPS Operator's agreement that the manner in which the Interconnection Customer proposes to implement such a limit will effectively limit active power output so as to not adversely affect the safety and reliability of the Area EPS Operator's system."

11.2 Power Control Limited Capacity

Using Area EPS Operator's approved Power Control methods, the DER Operator may limit the DER AC capacity. The limited DER AC capacity value may be used by the Area EPS Operator when performing impact studies if the means of limiting capacity is determined to be adequate by mutual agreement. Some of the reasons the DER Operator may choose to limit DER AC capacity include, to avoid system upgrades or to size the DER to be compatible with programs or tariffs[34].

For inverter-based DER systems 20 kW or less in Nameplate Rating, the Power Control limited capacity shall be implemented through utilizing the IEEE 1547 configuration settings[35]. For Power Control capacity limiting, active power limits at unity and non-unity power factors may be applied. The DER Operator shall propose the configuration settings to the Area EPS Operator for review and approval.

For rotating machines or inverter-based DER systems larger than 20 kW in Nameplate Rating, the DER Operator shall submit details of the proposed Power Control limiting method for maximum capacity limiting, along with settings, if applicable. The Area EPS Operator shall review and either approve the proposed Power Control method and settings or provide a response as to why the method does not provide adequate control. The DER system should use the IEEE 1547 configuration settings as the preferred means of Power Control limited capacity.

11.3 Power Control Limited Export and Power Control Limited Import

Power Control limited export and Power Control limited import can provide means of meeting the requirements of specific Area EPS Operator's tariffs or other technical requirements. The DER Operator shall obtain approval from the Area EPS Operator for any Power Control limiting system which is implemented. Power Control limiting for inverter-based DER systems with a Nameplate Rating of 20kW or less shall use a certified control system tested to UL 1741[36]. For these smaller systems, the DER Owner shall submit proposed settings to the Area EPS Operator for review and approval. For DER systems with a Nameplate Rating larger than 20 kW using a certified control system tested to UL 1741, the DER Operator shall provide test results showing the magnitude and duration of power import or export.

The Power Control limited export and import may be applied using a UL 1741 certified Power Control System to limit import or export. Additionally, Power Control limited export may be applied using the IEEE 1547 *maximum active power* parameter to limit export in the

[34] The applicable programs or tariffs eligibility may be based on a nameplate capacity rather than a configured value. Consult the tariff or program rules of interest to determine if the nameplate capacity governs any aspects of the interconnection.

[35] IEEE 1547 Table 28 Nameplate Information contains the available configuration parameters which may be altered as allowed by Section 10.4.

[36] Testing to the UL Certification Requirement Decision on Power Control Systems may be used in the interim.

management settings[37] in cases where the RPA is at the PCC. The *maximum active power* parameter in the DER management information shall be used as a static limit when employed for limiting export. Similarly, the Power Control System import or export limit shall be a static limit when employed for limiting export or limiting import.
The current approved standards-based approaches for Power Control limiting have a maximum open loop response time limit of 30 seconds for limiting inadvertent active power exchange with the Area EPS. Active power exchange may occur for a period of time within this 30 second limit due to Local EPS conditions such as block load changes. Reactive power exchange between the DER, Local EPS and the Area EPS may occur during normal operations, but level and amount of this exchange shall be in accordance with applicable agreements.

The configuration and settings governing the Power Control limiting functions shall be password protected, accessible only by qualified personnel, or protected by other means which have been approved by the Area EPS Operator.

11.4 Other Power Control Methods

While this technical document has attempted to provide guidance and standards for Power Control limiting methods, this is a new and quickly changing area. This technical standard shall not preclude alternate means of Power Control limiting which may be implemented by mutual agreement between the DER Operator and the Area EPS Operator. The DER Operator shall provide details to the Area EPS Operator for any proposed Power Control limiting function. The proposal shall include settings, equipment information, and any other information necessary for the Area EPS Operator to complete a review of the proposal. Non-export limitations based on relaying or load characteristics are examples of potential proposals from a DER Operator. It is recommended that the DER Operator consider using a standards-based Power Control limiting system prior to proposing alternate solutions.

12. Enter Service and Synchronization

When entering service, the DER shall not energize the Area EPS until voltage and system frequency are within the ranges specified in Table 9 or established by Area EPS Operator's TSM.

Table 9 Enter Service Voltage and Frequency Criteria

Enter Service Criteria		**Default Settings**
Applicable voltage within range	Minimum value	≥ 0.917 p.u.
	Maximum value	≤ 1.05 p.u.
Frequency within range	Minimum value	≥ 59.5 Hz
	Maximum value	≤ 60.1 Hz

[37] IEEE 1547 Section 4.6.2 allows for an active power limit to be set as an export limit when the RPA is the PCC. The parameter is found in Table 40 of IEEE 1547 Section 10.6.12.

The DER shall parallel and synchronize with the Area EPS in accordance to IEEE 1547.

13. Intentional Islanding

As an alternative to cease to energize and trip in response to voltage or frequency disturbances or unintentional island detection, a Local EPS island may be formed. When DER meets the criteria of Section 6.4, a Local EPS island may be formed rather than ride-through for voltage or frequency disturbances. If DER does not meet the criteria of section 6.4, the transition to the Local EPS island shall meet the rapid voltage change requirements of IEEE 1547. When paralleling a Local EPS island to the Area EPS, the Enter Service and Synchronization requirements of Section 12 shall be met.

DER systems designated by authority having jurisdiction as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by applicable industry code, shall be exempt from this section and may Cease to Energize and Trip or separate from the Area EPS without limitation. Scheduled intentional Local EPS islands are allowed in accordance with IEEE 1547 Section 8.2.2 and applicable agreements.

Intentional Area EPS islands shall only be allowed upon mutual agreement between the Area EPS Operator and DER Operator.

14. Test and Verification Requirements

14.1 Introduction

Prior to a DER system's initial interconnection or operation in parallel with the Area EPS, the Area EPS Operator may require verification and testing of the DER interconnection. The Area EPS Operator's TSM document is expected to be reviewed to understand the interconnection testing requirements. The testing of the DER shall depend upon the type, size and complexity of the DER system. For DER systems utilizing certified inverters, which meet the IEEE 1547 interconnection requirements, the testing shall be to confirm the proper installation and configuration of the equipment.

Type tests and conformance testing are related to the interconnection requirements and safety aspects. The operational compliance with applicable tariffs, which is often pertinent for storage, is not affirmed through the test and verification requirements outlined in this section.

The process associated with design, approval and execution of test and verification procedures follows:

- The Area EPS Operator shall define the characteristics of tests that are required by applying standards and best practices.
- The RPA shall be specified in the one-line diagram submitted to the Area EPS Operator with the Interconnection Application. The DER Operator shall denote the RPA where

the test and verification feature shall be applied in the written test procedure, if required.

- When required by the Area EPS Operator, the DER Operator shall provide written test procedure to the Area EPS Operator for review.
- The testing and verification procedures shall be reviewed and approved by a Professional Engineer when a Professional Engineer is required for design of the DER as specified by the MN DIP[38].
- The Area EPS Operator shall provide written feedback to the DER Operator, if written test procedures are required, indicating the determination if the test and verification meets applicable requirements. Prior to witness testing, the Area EPS Operator may require the DER Operator to attest the DER system is ready for testing.[39]
- The Area EPS Operator and the DER Operator shall arrange for qualified personnel to perform the test procedures. Each entity shall operate their own equipment.
- The Area EPS Operator may arrange personnel to witness the test procedures being performed by the DER Operator.
- The Area EPS Operator may evaluate the DER as-built installation, including as outlined in IEEE 1547.1, during this site visit to verify that the installation meets interconnection and interoperability requirements.

The applicable DER evaluation, commissioning tests and verifications, shall be performed per IEEE 1547, IEEE 1547.1, and Area EPS Operator’s TSM.

14.2 Full and Partial Conformance Testing and Verification

All DER used for interconnection with an Area EPS shall be tested to conform to IEEE 1547 interconnection requirements using IEEE 1547.1 conformance test procedures. Additional testing to affirm compliance with applicable tariffs may be outlined by the Area EPS Operator within their TSM. One way a DER shall be considered as conforming to IEEE 1547 is if it has been submitted by a manufacturer, tested and listed by an Occupational Safety and Health Administration (OSHA) Nationally Recognized Testing Laboratory (NRTL) for continuous grid interactive operation in compliance with the applicable codes and standards and is determined to be fully compliant. DER equipment shall be tested to conform to the IEEE 1547 requirements and listed in accordance with an OSHA NRTL.

All inverter-based DER units shall be UL 1741 certified. Certified DER equipment that do not require a supplemental DER device to meet IEEE 1547 requirements at the Reference Point of Applicability and where the impedance between the PCC and POC is less than 0.5% on the DER rated apparent power and voltage base shall be considered fully compliant. Partially compliant DER shall require further evaluation and possible testing. All DER systems shall meet the requirements of IEEE 1547 regardless of whether they are classified as fully or partially compliant.

[38] A Minnesota license Professional Engineer signature is required for certified system greater than 250 kW or for non-certified system greater than 50 kW as outlined in MN DIP 1.5.1.4.

[39] MN DIP Attachment C Certificate of Completion, is an example of certifying the DER system is ready for testing.

IEEE 1547 introduces the concepts of Reference Point of Applicability, which is located at either the PoC or the PCC. The IEEE 1547 standard section 4.2 should be referenced to determine the RPA, as the RPA is the point at which testing and verification requirements apply. Annex B in this document describes the relationship of these terms.

Figure 3 details the test and verification required steps when the RPA is at the PoC for a fully compliant DER Unit or DER system as well as a partially compliant composite DER system. Fully compliant DER Unit(s) require *basic* design evaluation and commissioning tests. Partially compliant DER Units(s) require *detailed* design evaluation. For example, a fully compliant DER Unit(s) with the RPA at the PoC is representative of a residential rooftop PV system. The DER Unit would be type tested by a NRTL resulting in a UL 1741 certification. IEEE 1547.1 details the Design Evaluation and Commissioning Test required for each of the combinations of fully and partially compliant DER with the RPA at the PoC and PCC.

Figure 3 Test and Verification Required Steps for RPA at PoC

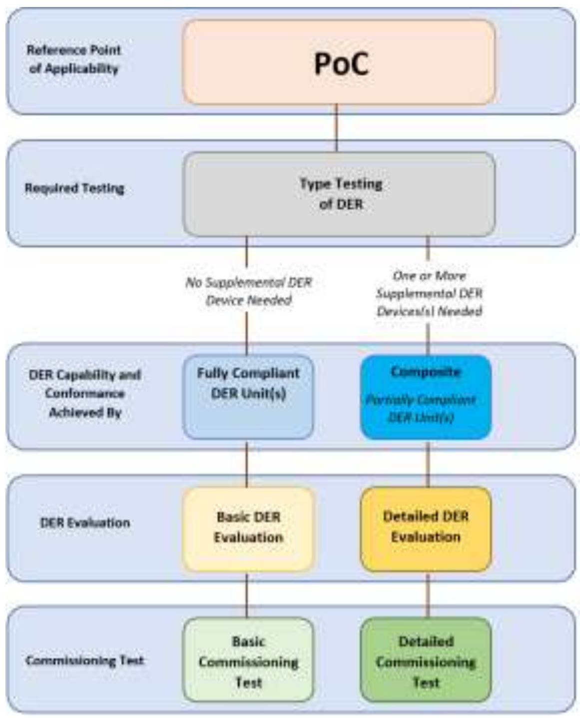
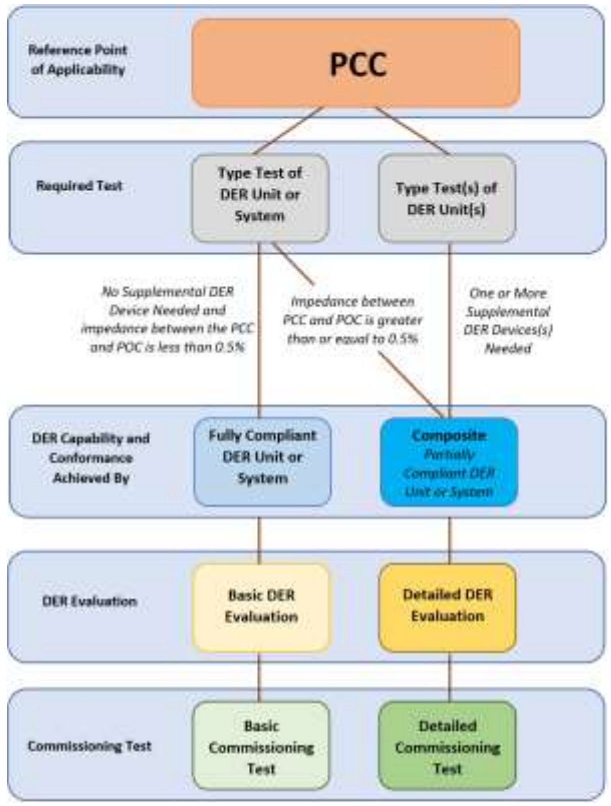


Figure 4 details test and verification requirements when the RPA is at the PCC. Requirements for fully compliant DER Units or systems and partially compliant DER Unit or systems are addressed separately in terms of required testing and evaluation.

Figure 4 Test and Verification Required Steps for RPA at PCC



14.3 Documentation

Testing and verification documentation requirements shall be specified in the Area EPS Operator's TSM. Fault current characterization information required in IEEE 1547, subclause 11.4, shall be provided to the Area EPS Operator upon request or per the Area EPS Operator's TSM.

14.4 Failure Protocol

In the event that a DER fails testing and verification, the DER Operator shall resolve any out-of-compliance items and resubmit or reschedule the appropriate items as defined by the MN DIP and Area EPS Operator's TSM.

14.5 Reverification and Periodic Tests

The DER Operator shall notify the Area EPS Operator prior to any of the following events occurring:

- Protection functions are being adjusted after the initial commissioning process.
- Functional software or firmware changes are being made on the DER.
- Any hardware component of the DER is being modified in the field or is being replaced or repaired with parts that are not substitutive components compliant with this standard.
- Protection settings are being changed after factory testing.

Prior to modifications to the DER triggering reverification, the DER Operator shall notify the Area EPS Operator's interconnection coordinator, as identified on the Area EPS Operator's website. Any of the above events may be cause for requiring reverification of the interconnection and interoperability requirements, per IEEE 1547 clause 11.2.6.

The Area EPS Operator may specify the frequency or time intervals for periodic testing consistent with Area EPS Operator's policies or manufacturer requirements.

14.6 Simplified Process Testing Procedure

The general process for field inspection and testing of an inverter-based DER that is less than 20 kW in size and approved through the Simplified Process, is outlined below. Specifics of the testing procedure and the responsibilities of the installer shall be identified in the Area EPS Operator's TSM.

General Process for Simplified Testing Procedures

- Verify installation matches design evaluation
  - Verify inverter model matches application
  - Verify certified inverter
  - Verify correct labeling / signage
  - Verify installation matches application one-line (i.e. connections, location of protection, disconnect switch, metering etc.)
  - Verify electrical inspection sticker
  - Verification of operational and protection settings

- Field Testing
  - On-off test
  - Open phase testing (if applicable for multiphase systems)

15. Operating and Maintenance Requirements

Operating and Maintenance Requirements may be required by the Area EPS Operator and are documented in Attachment 5 of the Interconnection Agreement.[40] The Operating and Maintenance Requirements are created for the benefit of both the DER Operator and the Area EPS Operator and shall be agreed to between the parties.

Operating and Maintenance Requirements may be reviewed and updated periodically to allow the operation of the DER to change to meet the needs of the DER Operator and the Area EPS Operator. There may also be changes required by external issues, such as changes in FERC and RTO recommendations or policies, which may require the updates to the Operating and Maintenance Requirements. Any updates to the Operating and Maintenance Requirements shall be agreed to between parties. In cases where mutual agreement cannot be achieved, see MN DIP section 5.3 and MN DIA Article 10.

[40] The Interconnection Agreement requirements are defined in the statewide Minnesota DER Interconnection Agreement (MN-DIA).

The following is a list of typical items that may be included as Operating Requirements. The items included as Operating Requirements shall not be limited to the items shown on this list:

i. Operational requirements, settings, and limits for DER when the Area EPS is in a normal condition
ii. Operational requirements, settings, and limits when the Area EPS is in an abnormal condition due to maintenance, contingencies, or other system issues
iii. Permitted and disallowed ESS Control Modes
iv. BPS or TPS limitations and arrangements that could impact DER operation
v. DER restoration of output or return to service settings and limitations
vi. Response to control or communication failures
vii. Performance category assignments (normal and abnormal)
viii. Dispatch characteristics of DER
ix. Notification process between DER Operator and Area EPS Operator
x. Right of Access

The following is a list of typical items that may be included as Maintenance Requirements. The items included as Maintenance Requirements shall not be limited to the items included in this list:

i. Routine maintenance requirements and definition of responsibilities
ii. Material modification of the DER that may impact the Area EPS

Annex A – Link to webpage containing Area EPS Operator Technical Specifications Manual (TSM)

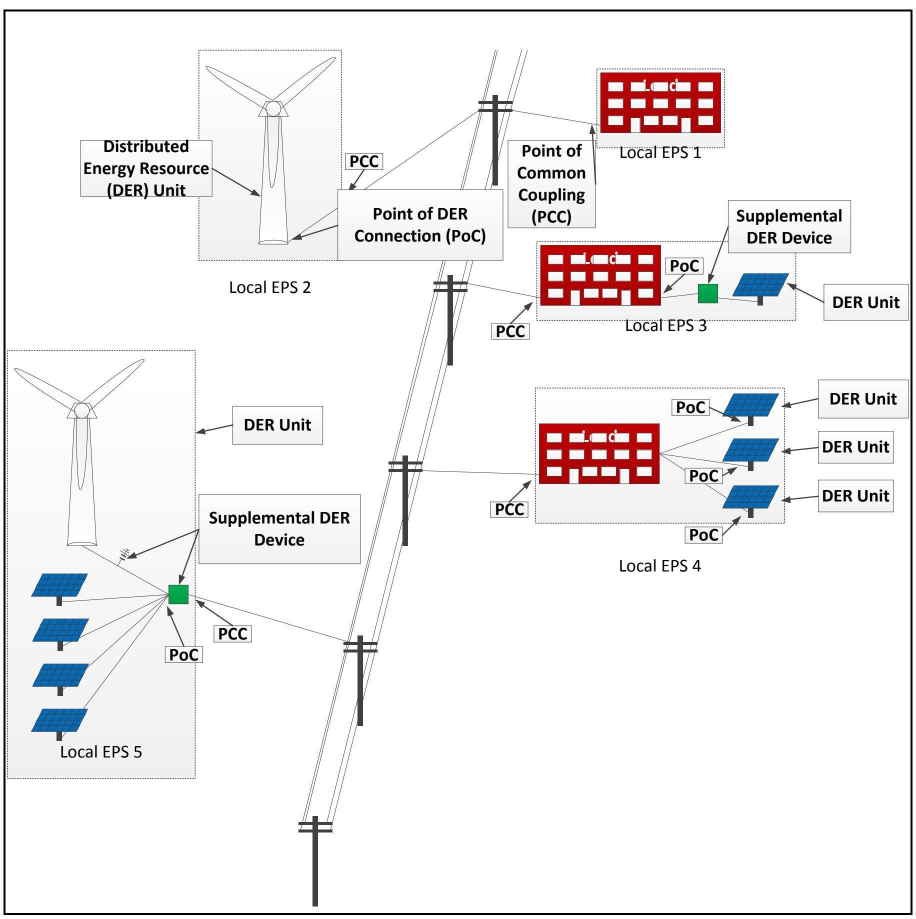
Below is the website address associated with an Area EPS Operator webpage containing the Operator's TSM:

Company	Website Address
Dakota Electric Association	
Minnesota Power	
Otter Tail Power	
Xcel Energy – Northern States Power Minnesota	

Annex B – Clarification on Reference Point of Applicability, Point of Common Coupling, Point of DER Connection, and Supplemental DER Devices

The reference point of applicability (RPA) is the location where the requirements in IEEE 1547 and IEEE 1547.1 apply. The TIIR adopts the RPA as the location to apply technical requirements. The RPA is usually at the PCC or PoC. A location between the PoC and PCC can be mutually agreed upon as a substitute for when the location is determined to be at the PoC. The influence of load on the overall Local EPS operating characteristics is a driver behind the need for the RPA to be at the DER PoC. For example, meeting the reactive power requirement for DER may not be feasible if the DER is relatively small compared to a reactive power load in the same Local EPS. Similarly, ground referencing of the Local EPS also affects the ability of a DER to meet certain protection requirements. For example, detection of a loss-of-phase is not possible without zero-sequence continuity[41] between the Area EPS and Local EPS.

Decision trees for determining RPA are described in IEEE 1547, Section 4.2.



[41] For example, a transformer delta winding breaks zero-sequence continuity.

Annex C – Anticipated list of topics in a TSM

1	**Introduction**
2	**Abbreviations and Common Terms**
3	**Performance Category Assignment**
4	**Reactive Power Capability and Voltage/Power Control Performance**
5	**Response to Abnormal Conditions**
6	**Protection Requirements**
7	**Operations**
8	**Power Control Systems**
9	**Interoperability**
10	**Energy Storage Systems**
11	**Metering Requirements**
12	**Signage and Labeling**
13	**Test and Verification Requirements**
14	**Sample Documents for Simplified Process**
15	**Appendix**

Attachment 1

The following clarifies which sections of the TIIR go into effect immediately and which are replaced with an existing technical requirement until the Commission provides Notice that IEEE 1547-2018 certified equipment is readily available ("Commission Notice".)[1] The "interim period" referred to below is from July 1, 2020, the date the TIIR goes into interim effect, until the Commission Notice announcing the TIIR is in full effect.

All sections of the TIIR shall go into effect on July 1, 2020 except for the following sections for inverter-based systems. Mutual agreement between parties does allow for utilization of the full TIIR during the interim period.

Section 4 (Performance Categories)
This section does not go into effect until Commission Notice. No alternate provision is in place during the interim period.

Section 5 (Reactive Power Capability and Voltage/Power Control Performance)
Sections 5.4 does not go into effect until Commission Notice unless mutual agreement exists between parties. In the interim period, the power factor requirements of Section 5.3 shall be used as default settings[2].

Section 6 (Response to Abnormal Conditions)
This section does not go into effect until Commission Notice. In the interim period, the following tables shall be considered default settings unless mutual agreement between parties exists.

Table 1 - Synchronous DER Response (shall trip) to Abnormal Voltages

Shall Trip – Synchronous DER		
Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Voltage (p.u. of nominal voltage)**
UV2	0.16	0.50
UV1	2.0	0.88
OV1	1.0	1.10
OV2	0.16	1.20

[1] MN PUC, ORDER 159427-01, Docket E-999/CI-16-521. Request input from the Technical Subgroup (TSG) of the Distributed Generation Workgroup (DGWG) as to when IEEE 1547-2018 certified equipment is "readily available" and delegate to the Executive Secretary the authority to notice when the full TIIR goes into effect in consultation with the TSG.

[2] IEEE 1547-2018 section 5.3.1, as referenced in the TIIR, does not apply in the interim period, but the constant power factor specification requirement can be applied.

Table 2 - Inverter DER Response (shall trip) to Abnormal Voltages

Shall Trip – Inverter DER		
Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Voltage (p.u. of nominal voltage)**
UV2	0.16	0.50
UV1	2.0	0.88
OV1	1.0	1.10
OV2	0.16	1.20

Table 3 - DER Response (shall trip) to Abnormal Frequencies

Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Frequency (Hz)**
UF1	0.16	59.3
OF1	0.16	60.5

Section 9 (Interoperability)
This section does not go into effect until Commission Notice. In the interim period, the Area EPS Operator's TSM shall be used. The Area EPS Operator's TSM shall contain Interoperability requirements comparable to section 5 (regarding metering and monitoring control requirements) of the 2004 State of Minnesota Distributed Generation Interconnection Requirements document.

Section 12 (Enter Service and Synchronization)
This section does not go into effect until Commission Notice. In the interim period, when entering service, the DER shall not energize the Area EPS until the applicable voltage and system frequency are within the ranges specified in Table 4,unless mutual agreement between parties exists.

Table 4 - DER Enter Service Criteria Ranges

Enter Service Criteria		Default settings
Applicable voltage within range	Minimum Value	≥0.917 p.u.
	Maximum Value	≤1.05 p.u.
Frequency within range	Minimum Value	≥59.3 Hz
	Maximum value	≤60.5 Hz

DER shall be capable of delaying enter service by an intentional adjustable minimum delay when the Area EPS steady-state voltage and frequency are within the ranges specified in Table 4. The adjustable range of the minimum intentional delay shall be 0 s to 300 s with a default minimum delay of 300 s.

Section 14 (Test and Verification Requirements)
This section does not go into effect until Commission Notice. In the interim period, the Area EPS Operator's TSM shall be used. The Area EPS Operator's TSM shall contain Test and Verification requirements comparable to section 8 of the 2004 State of Minnesota Distributed Generation Interconnection Requirements document.